Ontario

Ontario Energy Board

Smart Meter Implementation Plan

Draft Report of the Board For Comment

November 9, 2004

Smart Meter Implementation Summary

On July 16, 2004, the Minister of Energy asked the Ontario Energy Board to develop an implementation plan to achieve the Government of Ontario's smart meter targets for electricity: 800,000 smart meters installed by December 31, 2007 and installation of smart meters for all Ontario customers by December 31, 2010. Smart meters will allow customers to manage their demand for electricity to make more efficient use of Ontario's existing supply of electricity and reduce reliance on external sources.

The Minister asked the Board to identify and review options for achieving the targets and to address several specific issues. In developing this draft implementation plan, the Board has consulted with stakeholders through two processes. In July, the Board issued a discussion paper and invited comment. In late August, the Board struck four working groups of interested and experienced stakeholders to study the options and to identify detailed implementation issues. The Board has benefited greatly from this input and has considered it carefully in developing this plan.

The Board now seeks input from interested stakeholders and the broader public on the draft implementation plan outlined in this document. The Board will then prepare a final plan to submit to the Minister for consideration.

The smart meter initiative is both challenging and complex. Implementation will require the coordinated and committed efforts of many parties over several years. In developing the draft plan, the Board considered the technology to be used, how smart meter systems will be procured and by whom, and who should pay for the systems – as well as many detailed implementation issues. In making recommendations, the Board considered many factors, including the structure of the electricity distribution system in Ontario, the need to begin implementation promptly to meet the government's target installation dates, and the estimated overall cost of the proposed system. The more significant issues covered in the draft plan are summarized below.

Proposed smart meter system

The Board proposes a basic smart metering system in Ontario that would measure how much electricity a customer uses each hour of the day. Through wireless communication or other technologies, the data would be transferred daily to the local electricity distributor. The distributor would use that data to charge customers an energy price that varies depending on when the electricity was consumed. Customers would have access to data by telephone or Internet the following day. Distributors would transmit customer consumption data to retailers for those customers who had signed with retailers.

The proposed smart meter system would support current methods of charging larger customers. Some larger commercial and industrial customers pay delivery charges based on their maximum electricity demand or based on their power factor (rather than on total consumption, which is the basis used to determine the delivery charges for residential and smaller commercial customers).

The draft plan does not mandate a specific system or a particular vendor. The type of system that is best for any distribution territory depends on many factors, particularly customer density and geographic factors. Each electricity distributor will have to determine what works best in its territory, as long as the system selected meets the minimum technical standards proposed by the Board. Given the need to move quickly, the Board is proposing that distributors must select systems from vendors with at least 10,000 meter points in operation in a smart meter system.

The basic smart meter system proposed by the Board is based on one-way communication (data transferred from the meter to the distributor). The Board considered requiring two-way communication (signals can be sent to and from the meter) but concluded that it eliminated viable systems from contention and could compromise competitive bidding. Also, the basic system proposed by the Board does not include all technical features currently available from vendors. Distributors will be permitted to select smart meter systems that have enhanced functions, such as voltage monitoring, earlier payment, load limiting and remote cut-off. Inclusion of the cost of such enhancements in distribution rates will depend on a business case acceptable to the Board.

The Board expects that retailers and other energy services companies will be prepared to offer enhanced services for a fee to those customers who desire extra functionality.

Rollout of smart meters

The draft plan proposes that all new and existing distribution customers in Ontario, including all residential and small commercial customers, have some type of smart meters. General service customers with peak electricity demand between 50 and 200 kW will get a smart meter capable of reading demand (which is required to compute demand charges applicable to those customers). General service and industrial customers with over 200 kW of peak demand (maximum electricity use at any point in the month) will get interval meters that measure consumption in 15-minute intervals.

Large customers that have peak demands over 200 kW will get new meters first. These meters can be installed quickly because the meters will be the same as the ones already installed by many industrial customers. Starting in 2006, once a distributor has selected its smart meter system, industrial and commercial customers with peak loads from 50 kW to 200 kW will receive smart meters and all new installations (such as meters in newly constructed homes) will have smart meters. In addition to these priority installations, about 12% of the existing meters in the province will need to be changed to smart meters by December 31, 2007 to meet the government's target.

The Board is encouraging distributors to carry out pilot programs during 2005 to gain useful information about the installation and operation of smart meter systems before making final decisions on the particular system that they intend to choose.

Responsibility for implementation

Three parties will have key roles in the implementation process.

Distributors

Distributors will be responsible for choosing the type of smart metering system that best suits their regional conditions and customer mix. As they are now, distributors will continue to be responsible for the installation, servicing and reading of the meter.

The Board has concluded that distributors should be responsible for procurement and installation of smart meter systems because of their long-standing role in metering in Ontario, their knowledge of their customers and service territory, and the critical interface between the smart meter system and a distributor's own billing and settlement systems. The Board believes, however, that it would not be cost-effective to have approximately 90 distributors acting independently in their selection and procurement of smart meter systems. Therefore, the Board is proposing that distributors form voluntary buying groups to select and procure smart meter systems. Some distributor buying groups already exist for buying distribution equipment and other goods.

Implementation Coordinator

A single entity will be required to manage the implementation process, to monitor progress, and to coordinate the activities of distributors over several years. One of the responsibilities of this entity would be to review and approve the procurement plans of the distributor buying groups. One option that the Minister could consider is to have the Ontario Power Authority fulfill this role should Bill 100 be passed by the Legislature.

Ontario Energy Board

The Board will be responsible for setting up a regulatory framework for smart meters. That work will include: building smart meter costs into distribution rates; amending OEB codes governing metering and the activities of distributors; amending distributor license conditions; and, where appropriate, setting province-wide standards for distributor business processes, such as data presentment to customers.

Impact on customers

When a smart meter is installed, two things will change for electricity customers. They will receive timely information on consumption and the pricing plans offered by distributors will feature electricity pricing that varies by time of use.

The Board proposes that customers have daily access to their consumption data for the previous day via the Internet or telephone. Historical consumption data will also be available. Customers will have information on how much energy they consume during different hours and different days.

The Board is currently developing a regulated price plan that will be available to residential and other customers to be designated by the government. It is expected that this new plan will feature prices that vary by time of use. The combination of a smart meter and a "smart" price plan means customers will have the incentive and the ability to control their energy costs through moving usage to off-peak periods (for example, running the dishwasher at night) or lowering energy use during peak periods (such as setting the air conditioning a few degrees warmer during the afternoon). Customers will be able do this manually, by using automatic control devices that they purchase and install themselves, or via a contract with an energy services company to control devices automatically based on price or demand level. Customers will pay according to what they use and when they use it. And those who conserve will not subsidize those who do not.

The Board's regulated price plan may also feature special pricing for critical days when the electricity system is at capacity and wholesale commodity prices are very high. These are usually hot summer days when air conditioners are running on full or evenings during cold snaps when heaters, ovens and lights are all in use. While there are usually no more than 15 events like this each year, electricity at these times can be very expensive. The day before a critical pricing day, customers will be alerted by the broadcast media, such as radio and television and Internet, that prices will be high for that day. Customers with smart meters will be able to save by cutting back their use during those critical days.

Higher peak winter prices can have significant cost impacts on those customers who rely on electric heat and have limited ability to shift demand. Conservation programs may focus on support for mitigating technologies like thermal storage, heat pumps or conversion to natural gas heating.

Larger commercial and industrial customers that have not signed with retailers currently pay the hourly wholesale spot price for their electricity. Because they do not have interval meters, they are charged based on a system-wide load profile, which may have little resemblance to their actual hourly consumption. Once these customers receive smart meters, they will pay the hourly price on their actual hourly consumption.

Cost

The draft plan proposes that the capital and operating costs of the smart meter system be included in a distributor's delivery rates that are charged to all customers in a particular rate class, whether or not they have a smart meter. In addition, it proposes that the costs related to old meters and other distributor assets that are made obsolete by the introduction of smart meters continue to be included in distribution charges.

It is proposed that costs be included in the distribution rate as soon as a distributor starts to install smart meters. Because it will take several years to complete the installation of smart meters in a distributor's territory, the impact on customer bills will be small initially. It will rise as the implementation program progresses. Based on cost estimates prepared by working groups for the basic smart meter system being proposed, the incremental monthly cost for a typical residential customer by 2010 (when full implementation is complete) may be between $3 and $4 a month to cover capital costs and net operating costs. The total capital cost through to 2010 for the proposed system (meter, communications, installation and distributor system changes) is estimated at $1.07 billion. The net increase in annual operating cost for the province is estimated to be $50 million.

The cost estimates in the preceding paragraph, and in the draft report, are for illustration only. The Board sets electricity distribution rates through transparent public processes and has not yet set any rates that include the cost of smart meters.

Comments

Nine (9) copies of written comments on this draft implementation plan should be sent by November 26, 2004, referring to RP-2004-0196, to:

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Board Secretary
2300 Yonge Street, 26th floor
Toronto, Ontario M4P 1E4

And an electronic copy in PDF format to:
BoardSec@oeb.gov.on.ca

Individuals may file a single copy of their comments.

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1. Introduction and Paper Overview

1.1 The Directive

On July 16, 2004, the Ontario Energy Board received a directive from the Minister of Energy under section 27.1 of the *Ontario Energy Board Act*, 1998. The Minister directed the Board to provide a plan to implement smart meter targets. The policy of the Government is to install 800,000 smart meters by December 31, 2007 and for all Ontario customers by December 31, 2010.

This project has been assigned Board file number RP-2004-0196. The full text of the directive is available as Appendix A-1.

1.2 Objective

The government has said that it is desirable, through the installation of smart meters, to manage demand for electricity in Ontario in order to make more efficient use of the current supply of electricity and to reduce the province's reliance on external sources.

The Government asked the Board to consult with stakeholders on options for achieving the smart meter targets including mandatory and optional technical requirements.

The Board's aim is to develop the most effective and workable plan to achieve the government policy objective on smart meters and conservation. The Board has tried to balance costs and benefits and to be fair to ratepayers, distributors and competitive companies. By setting reasonable minimum standards, the Board has also left the door open for distributors and others to add enhanced function at extra cost where a business case supports this.

In making its recommendations, the Board took into account the technologies commercially available in the market to fulfill a specification that ensures competitive bidding, and the speed of implementation required to meet the Government's targets.

In developing the plan, the Board has seen evidence that providing smart metering systems for all Ontario customers is technically feasible. The time frame is challenging and all involved will have to commit to meeting the deadlines.

The breadth of the implementation will make Ontario unique in North America by being the first to:

- automate the reading of meters in a region with multiple distribution service areas;
- ensure that the system is capable of recording hourly data for every customer; and
- provide previous day's usage information to all customers so that they can review and understand billed energy based on consumption.

Smart metering is important for better energy use because the true cost of electricity at daily and seasonal peak demand is significantly higher than at other times. Smart meters measure how much energy a customer uses, and when. Smart meters will give customers a means of controlling their bill through controlling how and when they use electricity. See Appendix A-2 for further background and a discussion of how load shifting affects commodity price.

1.3 Approach

After receiving the Minister's directive, the Board prepared a discussion paper that outlined the major issues and asked for comments. The Board received 43 papers reflecting diverse viewpoints. The Board then invited stakeholders to participate in working groups. The Board formed four working groups: Metering Technology; Communications and Data Interface Technology; Planning and Strategy; and Cost Considerations. These groups met many times between September 1 and October 14, 2004. Each group developed discussion papers, reports and recommendations for the Board to consider in developing the draft implementation plan. The Board wishes to thank all participants in the working groups for their contribution of time, experience and insight. For a list of organizations represented on the working groups, see Appendix A-3.

The Board also commissioned a survey of current meter inventories and practices of local electricity distribution companies in Ontario. The preliminary data from that study have helped with overall estimates of costs, benefits and targets. Consolidated information from that survey is expected in time for the final plan.

This Draft Implementation Plan is being released to interested stakeholders, the industry and the general public for comment. Written comments are to be provided to the Board by November 26, 2004. The Board will consider these comments in revising the Plan for the Minister by February 15, 2005.

1.4 Structure of the Draft Implementation Plan

This section of the document describes the project. Section 2 is the implementation plan including roles and responsibilities, timelines, implementation approaches and deployment priorities. Section 3 outlines overall project costs and benefits, stranded costs and cost recovery approach. Section 4 contains the technical specifications for Smart Metering Systems in Ontario. Section 5 discusses other potential non-commodity time of use rates. Section 6 outlines the next steps in the implementation.

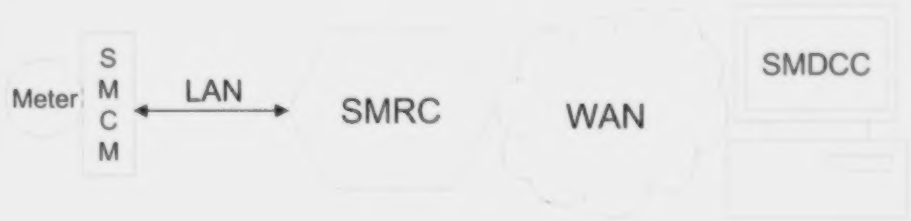
The appendices include a glossary of terms and acronyms, background information and further details of the draft plan.

1.5 Definition of Smart Meter Terms and System Components

The diagram and definitions in this section describe a smart metering system (SMS).

Figure 1. Typical Smart Meter System Configuration

SMS Component Definitions



SMS – Smart Metering System
SMCM – Smart Meter Communications Module
SMRC – Smart Meter Regional Collector
SMDCC – Smart Meter Data Collection Computer
WAN – Wide Area Network
LAN – Local Area Network

Smart meter vendor systems vary considerably in their infrastructure setup and may not match this diagram (for example, SMCM may connect directly to the WAN, SMCM may be housed in the substation, etc.)

1.5.1 Meter

All meters measure the consumption of electricity. A meter may be fitted with a register and display from which cumulative consumption can be read.

A meter may also record current and previous consumption in its memory for later retrieval. Readings stored in memory are time-stamped with the date and time the reading was taken. Readings may take the form of accumulated energy consumption or the actual energy consumed in the interval between readings.

A meter may be directly connected to the main supply through the use of a sealed socket. These are typically installed outdoors. For higher voltage applications, meters are usually isolated from the main supply through the use of instrument transformers and are secured in a locked meter cabinet.

1.5.2 Smart Meter Communication Module (SMCM)

The SMCM is a communication device housed either under the meter glass or outside the meter. It takes the information from the meter and transfers it through the Smart Metering System (SMS) to the SM Data Collection Computer (SMDCC). The SMCM may not have memory in the meter or in the SMCM. Information that is not stored in resident SMCM memory, may either be transferred at a pre-programmed time for storage in an intermediary collector device, or sent directly through the WAN to the SM Data Collection Computer.

1.5.3 Local Area Network (LAN)

The LAN is the communication module to the regional collector. Traditionally, the LAN is designed to carry information over distances of less than 1.5 km.

1.5.4 Smart Meter Regional Collectors (SMRC)

The regional collector can store data from the communication module as well as transmit it to the collection computer. If the communication module has little or no memory, the regional collector may act as the memory and storage point for the data, and in some cases completes the date and time stamping of the read data. The regional collector is the link between the LAN and the WAN, bringing data from the communication module in the meter to the data collection computer.

1.5.5 Wide Area Network (WAN)

The WAN is the communication network that transmits meter reads from the regional collector to the data collection computer. In some systems, the WAN extends from the communication module directly to the data collection computer. WANs are designed to transmit meter data over long distances, traditionally greater than 1.5 km. WANs transmit via fiber, telephone, and radio frequency over a utility-owned private network or a publicly-owned communication network.

1.5.6 Smart Meter Data Collection Computer (SMDCC)

Usage data is retrieved and stored in the collection computer. Depending on the level of sophistication of the Smart Meter System, the collection computer will issue operation/status reports following the download of data every 24 hours.

The SMDCC is also the central control point for registering new modules and accepting their data. As well, it connects the meter data to the distributor customer database, data repository and customer information system. It is the central control point for all communication module adds, moves, changes and programming of new time periods in the meters, if necessary. It also issues system status indicators and generates reports on the overall health of the system network and data collection operations.

2. Implementation

2.1 Overview

Achieving the Government's targets for smart metering systems will be a challenge. It will require an intense and well-coordinated effort by the Ministry, distributors, the Ontario Energy Board, a provincial implementation coordinator, retailers, Electronic Business Transaction hubs as well as the cooperation of customers.

2.1.1 Current Installed Metering

At present, distributors have responsibility for the meter. This includes specification, service, reading and complying with Measurement Canada requirements for registration, data storage and re-verification. As of 2002, there were roughly 20,000 interval meters installed for large commercial and industrial customers in Ontario. In addition there are approximately 50,000 customers with peak monthly demand over 50 kW that have three-phase meters with a demand pointer. The majority of the remaining 4.3 million Ontario customers have single-phase accumulation meters that register energy use. The distributor calculates consumption by taking the difference between the current and the previous reading.

2.1.2 Customer Categories

For the purposes of this draft plan, customers have been categorized into three groups.

Table A: Customer Groups

Customer Group	Customer Segment
1	Residential and General Service with peak demand under 50 kW
2	General Service with peak demand between 50 kW and 200 kW
3	General Service with peak demand over 200 kW

General service customers above 50 kW demand presently total about 50,000 while general service under 50 kW customers total about 350,000 and residential customers about 3.9 million.

2.2 Implementation Roles and Responsibilities

2.2.1 Local Distribution Companies

This report recommends that distributors continue to be responsible for metering service. This means that, distributors would be tasked with all aspects of implementation within their areas, including procurement, logistics, resourcing, deployment and communication. The Board recommends that distributors organize themselves into distributor buying groups for procurement and other aspects of the implementation where appropriate. They would need to develop procurement plans and business cases and submit them for review by the implementation coordinator. They would have to support large customer requests for early scheduling of meter installations and additional functionality in a timely manner. They would report their progress to the implementation coordinator.

The Board analyzed a number of alternatives. One option was full customer choice in meter provision and services (contestable supply). The Board has not recommended that approach because there is currently insufficient quantitative evidence available to the Board that shows that opening metering to competition would provide sufficient benefits to justify removing it from monopoly control. The experience in the US suggests that competitive metering has not realized significant benefits to consumers. There is also a concern that this approach might slow down the rate of smart metering deployment during the transition period. Another option considered was for a new regulated entity to take over all of the metering, meter reading and data management in the province and hand off data to the distributor. This model could realize economies of scale and allow more efficient utilization of the proposed smart metering investment. From an implementation timeline perspective, this option would require that a new regulated entity be set up and that Measurement Canada policies such as LMB-EG01 be changed in order to eliminate the distributor's legal responsibility for metering. With the already tight timelines imposed by the provincial targets, the Board felt that this would delay a much-needed early start to the initiative.

For a more detailed analysis of the options see Appendix B-1 (*Alternatives to Metering Remaining as a Regulated Distribution Function*).

2.2.2 Ontario Energy Board

The Board's role in implementation is to amend regulatory instruments and run stakeholder working groups to develop detailed standards for supporting processes. To meet the targets set in the directive, the Board should start these activities in January 2005.

The OEB would also investigate reports of non-compliance made by the implementation coordinator, whose role is described in the next section, and take appropriate action.

2.2.3 Implementation Coordinator

The implementation coordinator would ensure the progress needed to meet provincial targets, as well as an appropriate level of uniformity in technology. It would oversee procurement processes submitted by distributor buying groups. Distributors would provide updates on their progress and costs on a quarterly basis to the OEB and the implementation coordinator. In the event of distributor non-compliance, the implementation coordinator would make every effort to help distributors to get back on track. It would bring together and chair a steering committee made up of key stakeholders to resolve issues that parties might otherwise have difficulty in resolving themselves.

The Board feels that there is an inherent conflict were it to take on many of the functions of the implementation coordinator, given its later authority for rates. One option that the Minister could consider is to have the Ontario Power Authority fulfill this role should Bill 100 be passed by the Legislature. For other options considered for provincial coordination, see Appendix B-2 (*Provincial Coordination and Distributor Compliance*).

2.3 Implementation Timeline

Figure 2 provides an overall timeline to meet the December 2007 provincial target of 800,000 customers with smart metering. The chart is broken into workstreams for the OEB, the implementation coordinator and distributors. These are:

Ontario Energy Board:

- **Consultation** includes the completion of the consultation process by obtaining feedback on the draft implementation plan from interested stakeholders and the broader public, finalizing the report and submitting it to the Minister of Energy for approval by February 15, 2005.

- **Regulatory** includes amending rules, codes and standards, including any notice and comment periods required. Amendments may be made to the Distribution System Code, the Retail Settlement Code, the Affiliate Relationship Code, the Distribution Rate Handbook, licence conditions and rate orders. These are to be completed by mid-2005.

- **Provincial Standards for Supporting Processes** involves developing a provincial design baseline that would include such things as bill and Internet presentment standards, settlement standards and rules, editing and rebuilding standards for data, and XML communication standards. These are to be completed by mid-2005.

Implementation Coordinator:

- **Provincial Coordination and Project Management** involves appointing an implementation coordinator, setting up a steering committee, developing required business processes and systems for the implementation coordinator, overseeing distributor and EBT implementation progress, and resolving issues that hinder progress. It would require legislative change for the implementation coordinator to have binding authority over distributors. These activities continue through the life of the project. The implementation coordinator should be named in the first quarter of 2005.

- **Communication** includes developing a detailed communication plan involving both pro-active and reactive communication. The execution of the plan would involve coordinating Ministry of Energy, implementation coordinator, Board, and distributor communication efforts. These activities should begin in the second quarter of 2005.

- **Inter-Party Testing** is necessary to ensure that key players are ready. The testing will be made up of two stages: scenario testing followed by operational testing. Testing would take place in mid-2006.

Local Distribution Company:

Business Processes involve distributors designing new business processes to support their chosen technologies.

Smart Metering Deployment for Customer Group 3 (>200kW) includes continuing to install interval meters using telephone communications. This would begin in 2005.

Smart Metering Deployment for Customer Groups 1 and 2 (<200kW) includes contracting with smart metering system vendors to organize technology pilots, organizing and training installation field staff and deploying meters and communication infrastructure for <200kW customers. Choosing technology should begin in the first quarter of 2005.

- **Procurement** combines distributors into buying groups with common needs, runs RFP processes to obtain costs for required technology, develops and submits business cases (for functionality beyond the minimum requirements) and submits procurement plans to the implementation coordinator for approval, negotiates with and awards contracts to vendors, and organizes logistics. This should begin by mid-2005.

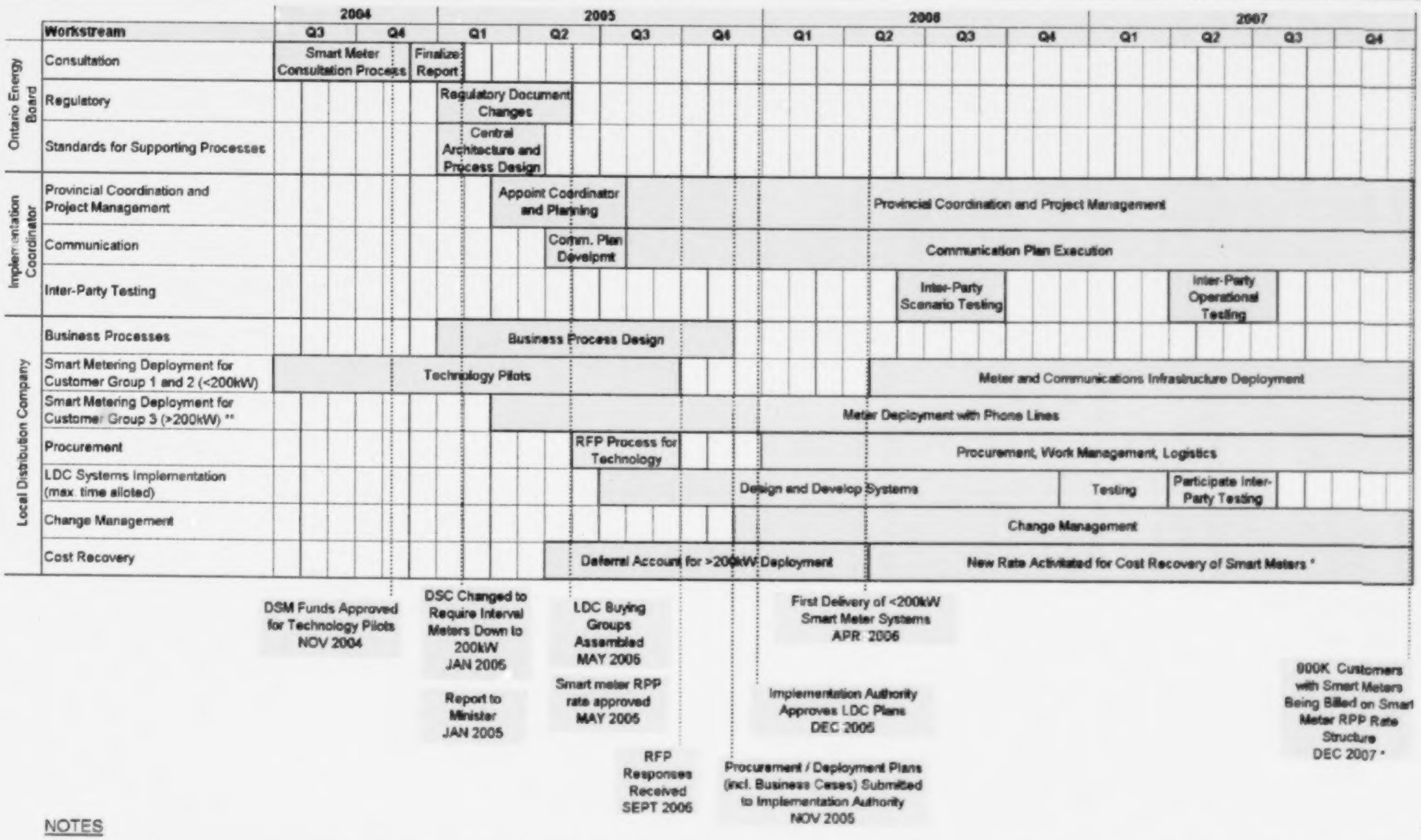
Distributor Systems Implementation includes implementing systems to support the smart metering technology, testing systems and participating in inter-party testing coordinated by the implementation coordinator. This should begin by mid-2005. Although Figure 2 shows this activity continuing through 2007, the Board expects that many distributors would be able to conclude much earlier.

Change Management involves documenting business processes, policies and procedures, establishing performance metrics, training staff on new business processes and technologies and managing staffing changes. It would also include the distributor portion of the overall communication plan. This would begin in the second quarter of 2005.

Cost Recovery includes reviewing cost recovery processes from the Board, submitting and obtaining approval on rate applications, and implementing new rates that allow for the recovery of smart metering costs. This would begin as part of the 2006 Electricity Distribution Rates process currently underway.

For a more detailed breakdown of implementation tasks, see Appendix B-3 (*Preliminary List of Implementation Tasks*)

Figure 2: Smart Meter Implementation Timeline



NOTES

* LDCs can start to bill on time based rates anytime after the rate is established but no later than December 2007 for groups of customers with smart meters. Cost recovery will begin when customers start receiving their smart meters.

** The implementation authority will not need to approve procurement plans for >200kW since there is an established process already in place for this customer segment and system functionality already exists for billing.

2.4 Procurement

2.4.1 Distributor Buying Groups

Ontario's varying customer density and terrain call for a range of systems. Distributors with similar needs should form buying groups and issue requests for proposals to help get the best pricing. Buying groups already exist for many equipment purchases, and new groups are forming to prepare for this and other initiatives. Four to six buying groups across the province should maximize the savings in each group from economies of scale. Buying groups are encouraged to conduct more than one contract over the life of this initiative to ensure that emerging technologies are considered in later years. The Niagara Erie Public Power Alliance Group, Cornerstone Hydro Electric Concepts Association Group and the Upper Canada Energy Alliance, three examples of groups, together account for more than one-third of the distributors in the province. The implementation coordinator would facilitate the creation of buying groups. The buying groups should be non-discriminatory and open to any distributor. It would be inappropriate to have any particular buying group gain exclusive right to a technology.

Forming these buying groups as part of this initiative may also encourage distributors to pursue efficiencies in other areas as well. These buying groups are often naturally grouped geographically and according to similar system requirements. This would result in easier integration of meter systems in the event of regional distributor consolidation.

Buying groups may also contract for metering, communications, logistics / warehousing, installation and meter data services.

The Board considered options for procurement including a centralized RFP to award multiple vendors, a centralized RFP to award a prime contractor who in turn would contract with several vendors; and a solution unique to Ontario where a single technology would be developed that would work for all meters in the province. The following explains why these options were not recommended.

Alternative 1: Centralized RFP to Multiple Vendors

This option is similar to the recommended option in that both would involve a task force of distributors making technology decisions while being facilitated by the provincial implementation coordinator. The major difference is that a central RFP would not give distributors full accountability for the process and would be a very complex and slow process to administer with over 90 distributors. It would hinder early adopters among distributors who are anxious to get started on their deployment since they would have to wait for the provincial process.

Alternative 2: Centralized RFP to Prime Contractor

This option would pass the coordination responsibilities of provincial deployment over to a prime contractor. The prime contractor would contract with individual vendors to provide distributors with technology alternatives. The option would add an additional layer of costs. With only one contracting entity, an issue with the prime contractor would put the entire provincial project at risk. Contracting with a prime contractor would likely be very complex and would take a long time to set up.

Alternative 3: Customized Solution

The option for a unique solution, where technology would be developed specifically for Ontario to work for all meters in the province. It would ensure an appropriate level of rationalization and would achieve economies of scale. But it would require lengthy up front analysis and development and would not be possible in the timeline set for the initiative. Many meter manufacturers did not feel that the size of the market justified a customized solution. It would also place additional risk on the province and would likely require additional approvals by Measurement Canada.

For a more detailed analysis of the options considered see Appendix B-4 (*Procurement Strategy*).

2.4.2 Procurement Process Oversight

The Board recognizes that there may be concern over the voluntary buying groups needing enough of any single product to get economies of scale. This level is generally between 50,000 and 100,000 units. The implementation coordinator would oversee the formation of buying groups and the development of procurement processes to ensure that all distributors were included and that the groups met the objectives. The implementation coordinator would develop guidelines on preparing plans. Buying groups would submit their procurement process for customers less than 200kW to the implementation coordinator. The implementation coordinator would assess the distributors' efforts to form buying groups and capture economies of scale. It is recommended that plans would need to be submitted no later than November 2005. Distributors would follow their current process for buying interval meters for customers greater than 200kW and would not require approval.

The Minister will have to determine whether the oversight role should be one of facilitator and information resource or of an approval authority. Legislative change would be needed for the implementation coordinator to have binding authority over the distributors.

The Board could use the implementation coordinator's assessment as a part of a later prudence review for setting rates.

2.4.3 Business Cases for Enhanced Functionality

Where a distributor intended to provide functions that went beyond the minimum standards described in Section 4.4 of this document, and required cost recovery, the distributor would have to submit a business case to the Board. This case would not be needed if there were offsetting distributor-realized savings or customers were not charged for this functionality. Customer charges would have to be approved by the Board. For example, a distributor with a large student population in rental units may have frequent transfer of accounts and a large number of special reads. This distributor may be able to cost justify remote disconnect/reconnect.

2.5 Deployment

2.5.1 Distributor Early Adopters Conduct Technology Pilots

Failed technology is one of the greatest risks to the smart metering initiative. The Board will encourage distributors to conduct pilots of a variety of vendor technologies with the testing to be completed by November 2005. Early adopters who conduct the pilots will ensure timely identification of technology issues and prevent issues from arising after more distributors start mass deployment. The implementation coordinator should share the results of the pilots to educate all distributors.

2.5.2 Deployment Work Programs

Based on resource skill sets, distributors will have two parallel deployment work streams. The following chart specifies each work stream. Since the two streams use different types of resources, there is no priority given to one over the other.

Table B: Work Programs for Customer Groups

Customer Group	Work Programs	Resources Used for Deployment	Low Cost Deployment Strategy	Number of Meters in Province
Group 2 and 3 >50kW customers and other three-phase metering	A	Certified meter technician	One off installations	Approx. 50,000
Group 1 Residential and GS <50kW with single phase metering	B	Installers with task specific training only	Mass deployment (distributor area sweep)	Approx. 4.3 million

2.5.3 Priorities in Meter Deployment

There is no strong evidence that any one Ontario customer group is a better focus for consumption shifting than another. U.S. studies may not necessarily apply to Ontario. As well, customer response to load shifting depends heavily on commodity price plans, distribution rate structures and effective DSM programs.

Certain priorities, however, suggest themselves. Putting smart meters in new installations minimizes stranded costs. Early adopters -- general service customers who request installation -- likely have load to shift and will produce early benefits. Publicly funded buildings are often referred to as the MUSH sector: municipal buildings, universities, schools and hospitals. They receive funding from tax budgets and increased energy costs mean decreased spending in other areas.

Below are the rankings for various customer groups that reflect these considerations. Small commercial and residential customers with three-phase meters are a lower priority because installation is costly, their loads are smaller and they may have more limited opportunity for response. The lowest priority is given to loads that currently have interval meters that lack the communication link for next day feedback.

Table C: Work Program A

Priority	Group	Number of Meters
1	New installations, service upgrades and meter changeouts	Approximately 50,000
2	General Service >50kW customers without interval meters who request early installations	
3	Publicly funded buildings (MUSH sector)	
4	Remaining General Service >50kW without interval meters	
5	Residential and GS <50kW (multi-phase)	
6	General Service >50kW who had interval meters but do not meet minimum smart meter requirements	

In Work Program B, new installations are a priority. Within the second group, the distributor is likely to do a street or neighbourhood at once.

Table D: Work Program B

Priority	Group	Number of Meters
1	New installations, service upgrades and meter changeouts	Approximately 170,000 /year
2	Residential and GS < 50kW (single phase)	Approximately 4,300,000

For distributor meter statistics and estimates, details on rationale for distributor priorities and mass deployment suggestions, see Appendix B-5 (*Deployment Priorities and Individual Distributor Targets*).

2.5.4 Distributor Targets

To meet the provincial targets, all distributors will need to complete the following by December 31, 2007:

- Deployment of 100% of smart metering systems for customers greater than 200kW starting in January 2005 (Work Program A)
- Deployment of 100% of smart metering systems for customers greater than 50kW but less than 200kW, starting after the approval of procurement plans by the implementation coordinator (Work Program A)

- Deployment of 100% of new installations, meter changeouts and upgrades on an annual basis starting after the approval of procurement plans by the implementation coordinator (Work Program A and B)
- Deployment of 12% of remaining meters (Work Program B)
- Completion of all support systems including data management system, CIS modifications, meter reading system and new interfaces into the EBT hubs.

It should be noted that distributors may contract out any functions including meter ownership, reading of meters, and data management and presentment to service bureaus. The distributor keeps the responsibility for the meter.

Figure 3 shows how these priorities can be translated into suggested targets for the province by year. Distributors may use these numbers as a guide to determine specific annual targets.

2.5.5 Deployment in Congested Zones

Every year, the IMO publishes an integrated assessment of the security and adequacy of the Ontario electricity system over the next 10 years. Currently the IMO has identified three congested zones (Toronto, western GTA and northern GTA). The IMO has suggested demand reduction initiatives should target these areas. The Board's draft plan addresses congestion zones with the following two recommendations:

- New installations should be the highest priority. Since high growth areas tend also to be congested areas, putting smart meters on all new installations will ensure that a greater proportion of meters will be deployed in high growth and, hence, high congestion areas.
- Distributors serving congested areas should deploy Work Program B meters in those areas first.

2.5.6 Exceptions

While distributors will not be precluded from replacing any meter, a number of meters may not need to be replaced with smart meters. The implementation coordinator would approve exceptions.

The criteria for exceptions should be:

- Cost-effective remote communications are not available; and
- the installations have minimal loads; and/or
- installations are not easily accessible.

This report recommends that the following initial list of pre-approved exceptions:

- Railroad crossings;
- Traffic lights;
- Street lighting;

- Cable TV amplifiers;
- Temporary services;
- Bus shelters;
- Emergency lighting; and
- Telephone booths.

2.5.7 Grandfathering of Existing Installations

It is recommended that two types of installations be grandfathered if installed before the date on which the Minister approves a smart metering implementation plan.

Existing Prepaid Meters

There are about 2,000 prepaid meters in the province that do not meet the minimum requirements of a smart meter. These meters have been used to achieve significant reductions in demand among the customers using them and should be grandfathered. The meters are not able to bill based on Critical Peak Pricing (CPP). Different rates would need to be set up for this group that do not include CPP (when implemented). If these grandfathered meters need to be replaced, the meter should be replaced with a smart meter. In some situations, this will mean that smart meter communications infrastructure will be underutilized until all grandfathered prepaid meters are phased out.

A smart meter could have the added function of prepayment.

Upgrading existing Interval Meters

Existing interval meters that are being used without communication should be upgraded to smart meters. This would be done by adding the appropriate technology. The data pulse stream could be used to drive an external, automated meter reading-module or a dial-up data collection process.

2.5.8 Distributor Specific Mass Deployment Strategies

Distributors may present alternative plans as long as they are consistent with the deployment priorities and meet the minimum requirements. Distributors should have the flexibility to manage their own deployments. Where these plans involve enhanced functions for meters or communications, a distributor that intended to seek cost recovery from ratepayers would prepare a business case to submit to the Board for approval. Examples of alternate plans include:

- Developing a "multi-meter" application, combining electric and/or water and gas installations to develop common communication platforms;

- Developing a WAN network that takes advantage of local opportunities such as fibre, unused radio bandwidth, phone line, cable or power-line carrier;

- Combining with other work management opportunities, work programs or conservation and demand management initiatives.

2.6 Customer Choice and Impacts

2.6.1 Mass Deployment and Requests for Early Deployment

It is estimated that one-off installations of residential meters cost five times more to complete than a mass deployment. Allowing residential and small general service customers to request early meter installations would result in higher costs and grossly underused communication infrastructure. For example, a network capable of supporting hundreds of meters might only be supporting a few. This would load costs at the beginning of the program. It is not recommended that smaller customers be allowed to request early installation.

Figure 3: Deployment Targets

	Customers				Priority Groups for 2007 Provincial Target			
LDC Name	**Res. Cust.**	**Comm. Cust.**	**Ind. Cust.**	**Total Cust.**	**GS >50kW**	**New Installs / Service Upgrades (per year)**	**Meter Changeouts (per year)**	**<50kW and residential**
TOTAL	3,921,528	426,583	10,623	4,359,412	49,937	99,705	76,297	4,309,475

Assumptions				
Deployment % - 2005	20%	0%	0%	0%
Deployment % - 2006	80%	75%	75%	4%
Deployment % - 2007	0%	100%	100%	8%
Deployment % - 2008	0%	100%	100%	20%
Deployment % - 2009	0%	100%	100%	28%
Deployment % - 2010	0%	100%	100%	40%

Deployment Timeline

Customer Groups	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**TOTAL**
GS >50kW	9,987	39,950	0	0	0	0	49,937
New Installs / Service Upgrades	0	71,040	94,720	99,705	99,705	111,388	547,597
Meter Changeouts	0	54,362	72,482	76,297	76,297	76,297	419,633
GS <50kW and residential	0	172,379	344,758	861,895	1,206,653	1,723,790	4,309,475
Total	**9,987**	**337,730**	**511,960**	**1,037,897**	**1,382,655**	**1,911,475**	**5,191,704**
Cummulative Total	**9,987**	**347,717**	**859,677**	**1,897,574**	**3,280,229**	**5,191,704**	
Provincial Target			**800,000**			**All**	

Monthly install rate	1,665	28,144	42,663	86,491	115,221	159,290

2.6.2 Group 2 and 3 Customers (>50kW) Requesting Early Installation of Meters

Since installations in this customer group will be more complex and will require a certified meter technician, they will be scheduled on a one-off basis, as opposed to mass deployment as with residential customers. The communication method used for Group 3 customers is likely to be dedicated or shared phone lines. Costs will therefore not increase significantly with early installation of meters, so customers who can benefit from changing their consumption behaviour should be able to begin immediately. The Distribution System Code should specify, for example, that distributors must install meters within 4-6 weeks of a request (except under extraordinary circumstances). Since there is minimal added cost for early installation, these customers should not pay any additional charge for early deployment. If the customer asked for enhanced functionality or requested off-hours installation, there might be an additional charge.

2.6.3 Group 1 Customers Requesting Early Installation of Meters (<50kW)

Customers in this group should not be allowed to request early installation because it would disrupt the mass deployment strategy of the distributor. This would increase costs and slow down deployment. Since LAN based communication infrastructure would need to be set up for meters to work, communications infrastructure would be underused.

2.7 Key Success Factors

An assessment looked at the potential barriers to the smart metering initiative. Appendix B-6 (*Potential Barriers and Mitigation Plans*) contains the full assessment. Based on the assessment, a number of key success factors were identified:

Effectively Manage Customer Relationships

Customer co-operation and support are essential to achieve the goals. The implementation coordinator should execute a careful and properly orchestrated communication and education plan that is consistent with messages at the local levels. Customers must be shown how using the new smart metering technology can save them money. Distributors should coordinate visits to customers' homes (e.g. to install meters) to minimize disruption to customers and better use distributor resources. Codes should clearly state the distributor's obligations for early installation or enhanced functionality. By taking these steps, a number of risks will be mitigated. Customers will be educated on the technology, how it will affect them and its scheduled deployment.

To realize all potential benefit, this initiative requires a strong communications strategy. It must explain how customers will save money and the province achieve greater conservation through smart metering.

The communications plan could include some of the following options:

- Ministerial announcement
- Mass communications
- Bill stuffer
- Distributor targeted communications
- Communication around the installations
- Six month follow-up
- Place holder for Regulated Price Plan
- Large customers communications

The implementation coordinator should also monitor stakeholder concerns about the smart meter program and communicate as needed.

To minimize the overall cost of communications and to ensure that regulated entities participate to the fullest possible extent, branding and pre-printed materials might be centrally coordinated. Any customer education undertaken by regulated entities beyond their normal level should be considered for cost recovery.

A more detailed communications plan, including guidelines and materials should be developed after the Minister accepts the final plan. It should take into account the timing of distributor deployments. Communications related to the Regulated Price Plan and creation of a conservation culture should be coordinated with smart metering communications.

Ensure Timely Decision-making

A number of Ontario and federal organizations must co-operate on consistent and timely decisions and policies. The Board recommends that the implementation coordinator be set up as soon as possible and its first priority be to communicate required decision dates and the impact of missing deadlines.

In addition, the implementation coordinator should chair a steering committee of stakeholders to ensure that issues among agencies are resolved in a timely manner. Representatives of distributors, the Board, the Ontario Power Authority (which may have the role of implementation coordinator), the Canadian Radio-television and Telecommunications Commission, EBT Hub, the Electrical Safety Authority, Measurement Canada, the IMO and the Ministry of Energy should be invited to participate. This will reduce the risk of delayed decisions that would jeopardize timelines.

Make Effective Resourcing Decisions

Distributors are unlikely to have sufficient resources in-house to fully deploy smart meters. Many distributors outsource meter reading and servicing and have few or no personnel to assign to the deployment. In other cases, collective bargaining agreements may preclude some contracting-out arrangements for distributors. Distributors should review and understand options/agreements regarding temporary and contract labour and develop a resource plan to achieve their deployment targets. They should train resources using available training programs and facilities where appropriate, hire resources from external service providers when needed and/or develop inter-utility resource sharing arrangements where possible.

Clear and Consistent Regulatory Framework

A key concern for distributors will be recovering the cost of this large capital investment. The Board will need to develop clear cost-recovery policies and procedures. Submitting procurement plans to the implementation coordinator for approval will provide distributors with some assurance that they are following an approved process and will reduce the financial risk of cost recovery. As well, the implementation coordinator will be setting interim milestones for distributors and will use the tools at its disposal to support distributors who need help meeting timelines. As noted, all distributors should be in a buying group and the groups must be large enough to ensure economies of scale. The Board and the implementation coordinator will have to be clear about the criteria for distributor buying groups.

2.8 Distributor Impacts

To help distributors understand the impact of this initiative on their business, Appendix B-7 (*Distributor Impacts*) includes distributor business process, system and staffing impacts and an illustrative systems architecture for data management and settlements. Since each distributor is different, the information provided in this section should be used as a guideline for further analysis.

3. Smart Metering Costs

The estimated capital cost of installing smart meters for all customers is estimated at $1.07 billion. Based on cost estimates prepared by working groups for the basic smart meter system being proposed, the incremental monthly cost for a typical residential customer by 2010 (when full implementation is complete) may be between $3 and $4 a month to cover capital costs and net operating costs. This estimate includes assumptions about the useful life of the equipment. Ultimately, the Board will decide on an allowable depreciation rate for smart meters.

This chapter looks at:

- **Impacts:** identifies the benefits to various stakeholders from smart metering systems.
- **New Costs:** identifies new capital and OM&A costs attributable to smart metering.
- **Stranded Costs:** looks at the equipment and systems that may be displaced by smart metering.
- **Cost recovery:** discusses the principles that should apply to recovering costs associated with smart metering and recommends some mechanisms for doing so.

3.1 Impacts

3.1.1 Customer Impacts

In order for any market to work efficiently, customers must be able to forego a product or service when prices are higher than they want to pay. For this demand response to be possible in electricity, customers must have three things: a price that changes with the real costs in the market; the ability to see the price and to take action; and the ability to have those actions measured in order to benefit financially.

The Board is currently developing a regulated price plan that will be available to residential and other customers to be designated by the government. It is expected that this new plan at some point will have prices that vary by time of use. The Board's regulated price plan may also feature special pricing for critical days when the electricity system is at capacity and wholesale commodity prices are very high. These are usually hot summer days when air conditioners are running on full or cold winter evenings when heaters, ovens and lights are all in use. Electricity at these times, usually no more than 15 events per year, can be very expensive. If the IMO calls a critical peak period, the alert can be sent by television, radio and print media. At a minimum, the distributor should add the information to the customer information call-centre and web-site, and institute a voluntary e-mail or auto-dial notification list. Customers will know these prices in advance and be able to act accordingly.

Customers will be able to control their consumption through moving use to off-peak periods (running the dishwasher at night) or lowering energy use during peak periods (setting the air conditioning a few degrees warmer during the afternoon). Customers will be able do this themselves, by using automatic control devices that they purchase and install themselves, or via a contract with an energy services company to control devices automatically based on price or demand level.

With a smart meter, customers will be measured on how much and when they use electricity. They will be billed according to that measurement and will be able to see, in a timely fashion, their use and how it affects their bill. The Board proposes that customers will have daily access to their consumption data for the previous day via the Internet or telephone. Customers will have information on how much energy they consume during different hours and different days. Historical consumption data will also be available.

The combination of a smart meter and a "smart" price plan means customers will have the incentive and the ability to take action. Customers will pay according to what they use and when they use it. And those who conserve will not subsidize those who do not. Customers with smart meters will be able to financially benefit by curtailing consumption during those critical days.

When these customers take action, the whole electricity system will see a benefit. Studies have indicated that when supply is scarce relative to expected demand, a reduction in demand of 2 to 5 per cent could reduce prices by half or more.[1] This is particularly critical during peak demand periods, when prices typically increase very quickly. It is important to remember that, because of the infrequency and short duration of the events, customers' total electricity bill savings may be less than 2 per cent. However, the system benefits of reduced demand near system capacity limits are large. Prices are lowered for all customers when some customers lower or shift demand. Uplift charges for congestion management and reserve capacity are also lower for all customers when the system peak is lower.

Higher peak winter prices can have significant cost impacts on those customers who rely on electric heat and have limited ability to shift demand. Conservation programs may focus on support for mitigating technologies like thermal storage, heat pumps or conversion to natural gas heating.

Larger commercial and industrial customers that have not signed with retailers currently pay the hourly wholesale spot price for their electricity. These large commercial and industrial customers, that do not have interval meters, are charged based on a system-wide load profile that may have little resemblance to their actual hourly consumption. Once these customers receive smart meters, they will pay the hourly price on their actual hourly consumption.

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[1] Rosenzweig, Michael, et al. "Market Power and Demand Responsiveness: Letting Customers Protect Themselves". The Electricity Journal. May 2003.

3.1.2 Distributor Operational Savings and Retailer Opportunities

Smart metering holds potential benefits for other groups. Distributors, for example, can use smart meters to get data that may allow them to optimize distribution systems. Customer complaints arising from estimated reads should fall. Retailers can use smart metering data to design pricing options and load control services that customers might find attractive. Both of these groups should be willing to pay for the benefits that they realize from the smart metering system options that are beyond the minimum functions, and so that part of the cost should not accrue to the customer directly.

To fully realize benefits, both distributors and retailers will generally face additional costs. The remote disconnect/reconnect feature, for example, has been promoted as a smart metering benefit that will cut the costs of managing delinquent accounts. The technology is not necessarily dependent on smart metering because paging technology allows the same result by triggering a disconnect switch in a sleeve installed on the load side of the meter. Utilities can apply this device with electromechanical meters if they wish since it does not rely on an AMR system for communication. The reason for the small take-up is the cost.[2] Manual disconnection cost can range from $20 for a simple meter pull in a suburban utility to several hundred dollars for a disconnection at the transformer. But with only a very small proportion of customers ever disconnected[3], there would seem to be inadequate justification for universal deployment of remote disconnect capability. In addition, year round use of the switch would require a load limiting attachment to accommodate the practice in Ontario of leaving a customer with some basic power during the winter season. Load limiting, if it could be made available in a remotely operable form, would increase the cost of the device even more.

In the retailer's case, load control services coupled with a firm price contract for power is a service offering that would probably be attractive to some customers. If an inexpensive customer communication system can be deployed to make this operational then retailers will likely offer the service. But if the service relies on increased functionality of the metering system then the same situation as above occurs. If that functionality is not a standard feature of the system, a retailer may not pay the additional costs on speculation that it could sell sufficient service contracts to make a return on its investment.

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[2] Remote disconnect devices range from $135 to $250 according to industry estimates. The ENEL project in Italy deploys remote disconnect in every meter but the meter is purposely built by ENEL for a 250 V secondary voltage that only requires a 60 amp interrupting capability. The comparable breaker in 120/240 V systems like Ontario would range from 125 amp up to 200 amp which is more costly.

[3] Based on informal surveying of distributors, disconnects involve less than ½% of customers. If remote disconnect was available and relatively cost free, distributors might use it more often to discourage delinquency, perhaps up to double the present disconnect rate.

Distributor operating savings from smart metering, detailed in Chart 1, Appendix C-1 (*Benefits*), are estimated to total about $0.39 per residential customer per month.

Almost all benefits of smart metering have this investment requirement to realize them. Chart 1, Appendix C-1 lists the benefits that were identified with some estimates of value and the offsetting cost to obtain the benefit. Analysis and calculations for these benefits are presented in the Chart notes to Chart 1 also found in Appendix C-1 (*Benefits*).

3.2 New Costs

Smart metering costs for the new single-phase residential meter and communication system are expected to average $250 for each meter installed. This includes the costs to modify existing systems and provide new data storage facilities and data handling software. This represents $2.47 on the average monthly residential bill.

The cost of each meter will vary among utilities because of distributor geography, customer density, customer type and the communication technology. The above figure, therefore, should not be used to benchmark any particular utility, but rather as an overall budgetary target to guide the project.

The estimate also excludes new operating costs that are not now being incurred and will have to be accommodated in distribution rates. An example of these is meter re-verification costs. Electronic meters have to be tested more often than electromechanical meters, so the cost of ensuring accuracy will increase with smart metering. Operating costs for automatic meter reading systems can also be significant. As a general average, communication maintenance is estimated to be about 1% of the installed capital cost of the system. Data storage and management will become a much larger task for distributors than presently and the costs may be significant. Presenting smart metering data to the customer is another new cost that potentially might be large, depending on the frequency of updating information and the quality of the presentment. Daily access to the data adds to the cost.

Small single-phase commercial customers not subject to charges based on monthly peak demand are assumed to use the same meter as residential customers and will probably cost about the same. Larger commercial and industrial customers will need more expensive solutions to handle demand charges. The estimated cost of serving these customers will vary with the technology installed, but because there are relatively few of them compared to residential and small general service customers, their impact on overall deployment costs for the project will not be excessive. For example, even if all were fitted with the kind of interval metering now deployed to large customers, the cost would still be under $50 million.

All of the new costs associated with smart metering are itemized in Chart 2 in Appendix C-2 (*Smart Metering Costs*). Taken together, these costs are expected to add a further $1.42 to the average residential customer's monthly bill. This is somewhat offset by the estimated $0.39 per month in distributor operational savings.

3.3 Stranded Costs

Most residential and small commercial customers in Ontario have electromechanical meters that record cumulative energy consumption only. These customers represent more than 95% of meter installations in the province. All electromechanical meters will be rendered obsolete by smart meters. Some distributors have deployed electronic versions of these meters, but their population is relatively small. Some electronic meters might be adaptable to smart metering systems.

Most large general service customers (> 50 kW) are on a thermal demand type meter that records peak demand usage for the billing period as well as energy consumption. Some of these are electronic and may be retrofitted with a communications device to permit hourly reading, in which case there will be no stranding of these assets. However, most thermal demand type meters in service today are not electronic and will have to be replaced by a smart meter, resulting in some stranded costs.

The largest commercial/industrial customers have interval meters that record hourly usage and are interrogated by the distributor using telephone lines. These interval meters will be left in service and will therefore not be stranded.

Other stranded costs may arise from distributor systems that are incapable of operating in the smart metering environment. Chart 3, in Appendix C-3 (*Stranded Costs*), lists these potential sources of stranded cost.
Stranded costs will not be insignificant. The net book value today associated with meter hardware that will be made obsolete was estimated from survey data at $473 million, not counting the cost of removing and handling the old meters.[4] This figure is not an appropriate measure of costs that will be stranded because some assets will continue to be used and depreciate normally through 2010.[5]

There is a limited potential to reuse this hardware. Residential meters are worth only about $20 on average on distributor books and the cost to prepare and ship them elsewhere might exceed that, while new meters of this type cost about $40. The Ontario meters are also equipped with a test dial, a requirement unique to Canada that might make them less attractive to foreign jurisdictions.

Three-phase meters used for General Service customers might be more readily redeployed, but given the number of smart metering conversions going on in the world, there may be a glut of used equipment available that would limit prices. Secondary voltages used in Ontario might also limit redeployment of these meters outside the province. For example, fixed range units operating at 600/347 V cannot be redeployed to the United States where the common voltage is 480/277 V. Although meters installed in the past five years are probably adaptable to other voltage standards, older ones are likely not to be. For these reasons, resale of Ontario meters is not expected to significantly offset stranded costs.

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[4] Removal and handling is assumed to be attributable to the smart meter installation but if it is to be shared then possibly $10 of meter removal costs might be recorded as stranded in the old meter – this would increase the stranded cost by about $43 million.

[5] Assume 15 years left on depreciation schedule and $473 million at 7% average cost of debt i.e. no rate of return assumed on stranded assets. Assuming the result is allocated on a volumetric formula based on consumption then 40% will be allocated to residential customers.

3.4 Cost Recovery Principles

There are three types of costs to be considered in the implementation of the basic smart meter system: capital costs for meters, communication, associated systems for data handling and installation; on-going operating costs for reading, service, and re-verification; and stranded costs. The capital and operating costs are incremental to current rates. The costs of shared services (associated systems and some communication infrastructure costs) come at the beginning of the project. All customers will end up benefiting from their use.

In evaluating recovery options, the Board considered four principles:

- Cost recovery mechanisms should be reasonable and timely;
- Allocation of costs should be fair and related to benefits;
- Recovery should promote economic efficiency, where possible; and
- Recovery should be consistent among distributors.

The Board considered three ways to recover the incremental costs.

Despite the general benefits to society and the electricity system of the program, the Board rejected the idea of a general tax as not apportioning costs and benefits equitably.

The Board also rejected the concept of recovery through a capital contribution (upfront payment from customers) for most customers. It would create complexity around the treatment of common capital costs such as system changes and shared infrastructure. It would be a change from current practice for meter costs in residential and small commercial rate classes. It also does not address on-going operating costs. A customer could also end up paying for capital contributions more than once due to moving between distributor areas. Finally, it inhibits affordability (rate shock) by spreading costs over a short period rather than the used and useful life. As an example, a smart meter may have a depreciation period of 15 years.

The only option meeting the four principles was recovery through distribution rates. The two most likely options are discussed in detail below.

For either option, a cost reporting and monitoring system is needed to evaluate cost prudence as the smart metering project is rolled out. The details of that system need to be developed over the next year as part of the 2006 Electricity Distribution Rate process. This process also needs to consider the appropriate depreciation period for capital costs to avoid burdening future ratepayers for the benefits enjoyed by current ratepayers.

Appendix C-4 (*Recovery of Smart Metering Costs*) discusses further options for cost recovery in fixed or volumetric charges. The Board needs to decide in a future rate case if customers enjoy benefits equally or if those with higher use get greater benefits.

3.4.1 Recovery of program costs from all customers within a class

Under this option, distributors would forecast the capital and operating budgets for the entire project and the amount to be spent in each year, allocated to rate classes. Cost allocation according to classes is appropriate since different classes will have different meter costs, installation costs and stranded costs based on the complexity of existing and future equipment. The budget would be included in revenue requirement and rates for each class of customer for 2006 and beyond. Each year for each distributor, the Board would revisit the incremental rates, the budget and the progress toward targets to adjust the revenue requirement for the following year.

This spreads the cost of the program across all customers in a class. The capital costs of shared services are borne by all customers who benefit directly and indirectly. Distributors would get forward certainty of recovery for prudent spending. The portion of rates related to smart meters will be higher once all are deployed. The annual increment will depend on how many meters are installed in a particular year.

3.4.2 Recovery of program costs in each class only from customers with smart meters

An alternative is to add smart metering costs to the distribution rates only of customers who have had them installed. This is a more complex cost allocation exercise.

It is likely that the Regulated Price Plan will have two components: a fixed-price plan for customers with common accumulation meters and a time-dependent price plan for customers who have smart meters. In order to provide the proper bills, distributors would have to be able to differentiate between these customers. This will in effect create sub-classes of customers in each class, e.g. General Service accumulation-metered customers and General Service smart-metered customers.

Distributors would forecast project costs to be recovered in each year as part of revenue requirement. However, distributors would have to distinguish between shared costs and individual customer costs. It would be unfair to burden early smart meter customers with all the upfront system costs since all customers will ultimately benefit. Distributors would have to either attribute a significant portion of shared costs to fixed-price customers or defer that portion of costs until the customers are using them. Deferral accounts increase future rates and should be avoided if possible. If they are used, they need to be disposed of in an annual review.

Each distributor would also have different rates for each of the sub-classes. These rate sub-classes would be in effect until the deployment is complete.

This approach is driven by the ratemaking principle of cost causality. That is, customers who will be the principal beneficiaries of smart metering should pay the cost. However, it ignores the price benefits to accumulation-metered customers as a result of load-shifting by smart metered customers as described in section 3.2.1.

3.4.3 Recovery of Costs for Customers over 200 kW

Currently the Distribution System Code requires that customers with interval meters pay the incremental cost of the installation. All existing customers over 1000 kW and many customers over 500 kW or less have paid for their meters. The Board will decide as part of its amendment of the DSC whether or not to continue to require customer contribution for interval meters. If not, distributors would have to have a deferral account for spending that takes place in 2005, before 2006 rates can be changed.

3.4.4 Enhanced System Features

System functionality beyond the basic system may be installed, but the starting point should be that the party who benefits bears the incremental cost. If a distributor thinks an enhanced feature will benefit customers, then it will need to justify that benefit to the Board before being allowed to recover the cost from customers.

3.4.5 Stranded Cost Recovery

Stranded costs could be managed by transferring them out of ratebase and into regulatory assets. A rate equal to the depreciation expense that would have been charged, had the assets remained in service, should be used to allow distributors to recover their undepreciated capital costs. Stranded costs could be separated by customer class and recovered accordingly. This will have no impact on rates, but will extend the recovery period for the assets to about 15 years and may limit rate setting flexibility during that period. Recovery can begin with the smart meter deployment as a uniform charge to all customers in each distributor rate class for administrative convenience and consistent treatment of all customers. Alternatively, it can be staged to coincide with the point at which a customer actually receives a smart meter, if causality governs when cost recovery begins. See Appendix C-5 (*Recovery of Stranded Costs*) for further discussion.

4. Smart Metering System Minimum Requirements

4.1 Customer Groupings for Minimum Smart Metering System Requirements

Customers have been segmented into three groups according to the data needed to apply current and potential rate charges and commodity prices. The data needed drive the base level requirements for the smart meter system. The following chart determine the customer groups and meter data requirements. Group 3 systems will be similar to the current Distribution System Code requirements for interval-metered customers.

Table E: Customer billing and data requirements

Customer Group No.	Customer Segment	Billing quantities	Meter Data Collection Requirements	SMS Specification
1	Residential and General Service < 50 kW	kWh	Hourly data Single-phase	See section 4.4
2	General Service 50 kW – 200 kW	KWh kW	Three phase hourly data with in-meter time stamp	See section 4.4
3	General Service >200 kW	kWh kW kVA/kVAR	Three phase 15 minute interval data potentially with power factor	Remote interrogation by established distributor practice

The smart metering system specification is primarily for Group 1 and 2 customers. Interval meters are normally used for Group 3 customers to record power factor (kVA) or reactive readings (kVAR). Interval meters are usually interrogated by the distributor using dedicated or shared telephone lines.

There are a few customers who do not fit into these three categories. For a discussion of the technology appropriate for their circumstances and other specialized meters, please see Appendix D-1.

4.2 Meter Specifications

Under the *Electricity & Gas Inspection Act*, Measurement Canada approves meters for trade and defines and enforces minimum accuracy and re-verification requirements. Manufacturers and vendors must get approval of their product from Measurement Canada.

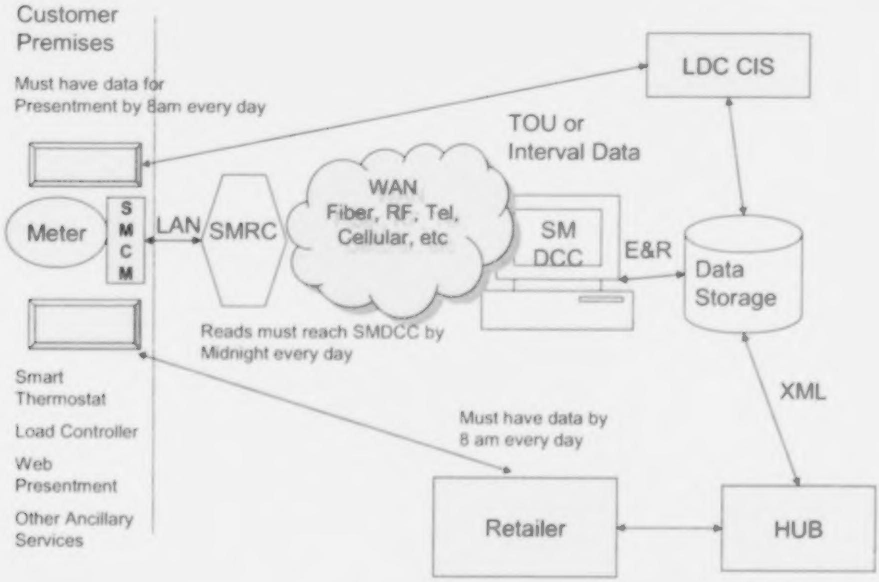
There may not be enough currently approved products to guarantee competitive bidding for all customer densities. The approval process can take between six months and two years depending on the level of innovation of the product. Vendors should seek approval as soon as possible if they expect to serve this market.

The Board is recommending that a smart meter must have a read resolution of 0.01kW to provide granularity for settlement. See Appendix D-2 for the meter specification.

4.3 Required SMS Service and Information Flow

Figure 4 shows what happens after the meter usage information arrives at the data collection computer. The meter data must be edited and rebuilt and moved to the data storage/warehousing. The distributor can upload the actual billing reads from data storage into its customer information system. Importing only the billing reads would involve fewer upgrades to existing customer information systems. The data storage facility can warehouse the data for on-line access requirements for both the customer and for transporting data in XML format to a retailer.

Figure 4: SMS Applications and Information Flow


Customer Premises
Must have data for Presentment by 8am every day
LDC CIS
TOU or Interval Data
WAN Fiber, RF, Tel, Cellular, etc
Meter
S M C M
LAN
SMRC
SM DCC
E&R
Data Storage
Reads must reach SMDCC by Midnight every day
XML
Smart Thermostat
Load Controller
Web Presentment
Other Ancillary Services
Must have data by 8 am every day
Retailer
HUB

Note: Once the meter data transports the reads through the SMS to the data repository, all services beyond basic customer presentment of usage information, such as load control/cycling, messages to smart thermostats, and enhanced web presentment, are considered enhanced services and are not part of the minimum SMS requirements.

4.3.1 Minimum SMS Functionality

The Board recommends a minimum functionality for the system. The distributor must ensure that its chosen system adheres to the minimum requirements and that the information it collects can be delivered to the customer and retailer as outlined herein.

The Board considered bi-directional communication as a minimum requirement. It concluded that specifying bi-directional communication eliminated viable systems from contention and could compromise competitive bidding. Therefore, the Board did not include it as a basic requirement. Also, the basic system proposed by the Board does not include all of the technical features that are currently available from vendors.

4.3.2 Enhanced Functionality

Vendors may offer systems with functions that go beyond the minimum at competitive prices. Enhanced functions can be built into the system or can be ancillary devices that assist the customer in controlling load. A list of some of these features is provided in Appendix D-3.

4.4 Minimum SMS Requirements

4.4.1 Minimum Technical Requirements

The Board is proposing the following minimum requirements for smart metering systems.

Key requirements of the system include:

- Systems must meet federal and provincial metering, electric safety, and communications requirements necessary to provide legal measure to the customers within the province of Ontario

- The system must be able to provide hourly consumption data from every meter connected to it without the need to remove the meter or visit the site. Distributors may, at their option, compress hourly data into time-of-use (ToU) and critical peak pricing (CPP) format. However, if compressed data are used, the system must have a two-way communication link between the communication module and the collection computer to reconfigure the unit to comply with any changes in ToU and/or CPP periods.

- The distributor must provide daily feedback to customers on their previous day's energy use. This information must be available in hourly intervals for at least the first four months after the Smart Meter is installed. Reads after that period may be compressed (if this feature and two-way communication link exists) to transmit the usage by TOU and CPP periods according to the relevant rate schedule. The information on the previous day's use must be available to the customer by 8:00 am each morning. See Appendix D-4.

- Reads acquired by the Smart Meter Data collection computer must be identical to the data retrieved from the meter. Hourly reads must retain the precision of the meter -- i.e., 10 Watt hours (.01 kWh) per interval.
- Hourly reads and pricing changes of the TOU and CPP registers must, if necessary, occur on the hour with 24 hours advance notice. Reconfiguration of the TOU and CPP registers to comply with changes must be completed 16 hours after notification of the change. For time reference information see Appendix D-5.
- Distributors must choose systems that have a proven track record in the field, with at least 10,000 units that comply with the proposed technical requirements installed and working.
- The architecture of each SMS must include sufficient redundancy to ensure the integrity of data collection and adherence to performance specifications outlined in this document. See Appendix D-6 (*Smart Meter Technology requirements*).
- Read transmission success rate must be over 95% over any three-day period.
- Missing reads must be logged and reported through the system by 6 am the following morning. An automated process called Editing and Rebuilding (E&R) will be specified by the OEB and will be implemented to standardize the method for filling in data gaps. See Appendix D-7 for an outline of proposed E&R requirements.
- The system must be able to construct the peak hourly demand for Group 2 customers. It must collect data time-stamped in the meter or be able to read TOU registers or demand registers in the meter.
- The system must be capable of providing the same level of functionality for the initial implementation as for full-scale deployment in the distributor's service area. Monitoring, management and data collection capabilities of the system must be measured to SMS specification standards.[6]

4.4.2 Smart Meter Data Collection Computer (SMDCC) Monitoring & Reporting Capability

The collection computer's main function is to confirm the number of end points that are connected and operating on the system. The database in the computer connects the meter information to the customer's account information in the distributor's customer information system.

The collection computer also monitors the overall health of the system's transmissions and all network operations. Upon completion of the nightly (or more frequent) read transmissions, a number of reports must be generated by the computer that enable the distributor to evaluate how well the system is operating.

---

[6] SMS functionality refers to the ability to meet read and interval requirements and data transmission throughput as specified in the SMS Functionality Specification and resulting distributors' RFP.

There are a number of critical factors that could put at risk the 95% read transmission success rate. These include:

- Network failures;
- Communication link failures;
- Power failures;
- Memory capacity issues;
- Meter failures; and
- Problems verifying reconfiguration of time parameters for systems using TOU data.

The system must be able to alert the distributor immediately to any of these. Any items of a non-critical nature must be trended, so that any anomalies that could potentially impact the system over time are monitored. These reports, called Non-Critical SMS Reports, are delivered after the nightly read transmissions.

Minimum Non-Critical SMS Reporting

- Successful initialization of modules installed in the field;
- Discrepancies in module and CIS links;
- Successful capture of readings – benchmark of the 95%;
- Read reports;
- Alarms and status indicators at modules;
- Suspected tamper and trending reports;
- Unsuccessful capture of readings – benchmark of less than 5%;
- Communication link functionality monitoring; and
- Status indicators for regional collectors.

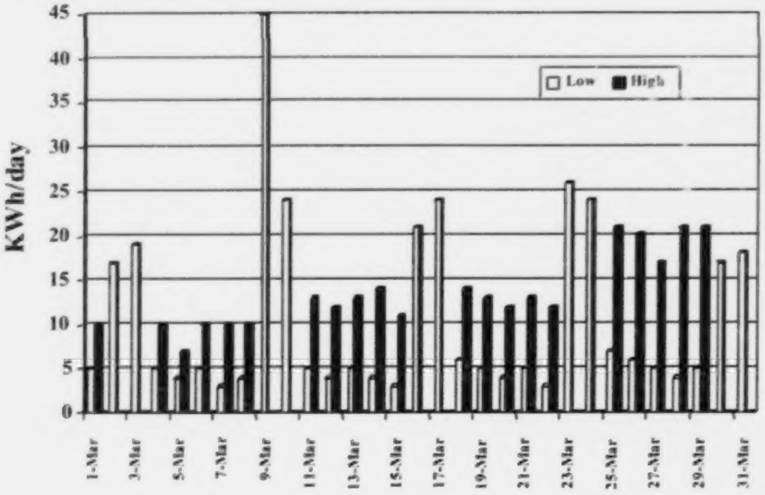
For the basis of the smart metering system request for proposal, see Appendix D-6.

4.5 Customer Information

For Ontario to meet its goal of 5% demand reduction by December 2007, customers must have the tools to understand their energy usage and the ability to change their patterns.

The ability to see their consumption by hourly intervals is expected to provide customers with the necessary information. Providing this information in a manner that reflects their usage in specific rate periods is also expected to be of value and importance in assisting the customer to control consumption. See Figure 5.

Figure 5: Sample Customer Monthly TOU Consumption



Pricing for all rate periods in each 24-hour period must be estimated and presented to the customer with the usage information by 8 am every day.

For energy usage comparison purposes, 13 months of on-line data must be available to the customer.

The Board must develop standards for bill and Internet data presentation to ensure that customers understand the feedback information.

If the IMO calls a critical peak period because the Province's energy system is expected to be near capacity, the notification must go out no less than 24 hours before the critical period begins. The alert can be sent through television, radio and print to make sure that the most possible people are aware of the critical call, are aware of the price increase and can avoid high bills by reducing consumption. At a minimum, the distributor should add the information to the customer information call centre and web-site. A voluntary e-mail or auto-dial notification list would be even more helpful. The Ministry should investigate ways of using emergency broadcast notifications.

Additional details regarding Minimum Requirements for Customer Information are provided in Appendix D-8.

Customer Usage Information Access Options

Distributors should provide daily use information to customers by: automated voice response, customer service support line, Internet and/or e-mail.

For further details on Customer Presentment Options see Appendix D-9.

4.6 Information Detail Parameters To Third Parties

Retailers will have access to the same level of data as customers. If the retailer needs hourly data for any customer not currently receiving this level of data, the retailer will be obligated to pay the increased cost of collecting this data. Information presented to the customer must be available for downloading by authorized retail energy service entities in standard format.

4.6.1 Standard Format for Data

This report recommends that retailers receive meter data from distributors the following day. Currently, these data are transferred through the electronic business transaction (EBT) system of hubs. The XML standard that was built to support EBT for market opening is expected to be the most viable option for transferring use information to the retailers. The distributors will still have to make the data available in XML standard format. For the data to continue to flow through them, the hubs would need to modify their systems to handle the higher data volume. The implementation coordinator would test hub readiness during Inter-Party Testing. In the event that hubs were not ready, retailers would be able to make other arrangements to receive the meter data by the next day.

4.6.2 Access to Historical Data

The Retail Settlement Code states that two years of customer usage data must be available. Smart metering data that has been validated and used to calculate and settle the bill should be available online. An additional seven years of data should be available off-line.

As noted, the customer's previous day's usage information must be available for access by the retailer by 8:00 am the following day. Data that must be edited must be available in rebuilt format within three days.

For alternate options for distributors on SMS system management and data collection operations, see Appendix D-10.

4.7 Distributor Guidelines for RFP Development

The inherent strengths and weaknesses of each SMS are based to a large degree on the telecommunications medium used to transmit the data. Diversity in the type of customer base, demographics and telecommunications infrastructure availability will necessitate distributors selecting systems that are most appropriate, cost effective and available in their service area. Apart from infrastructure availability, the distance between meters is often a key factor in SMS selection as it will determine system performance and ultimately the overall cost per point of the entire SMS. The information in Appendix D-11, provides more structure, technical information and functionality guidelines on the various vendor SMS options available to distributors, while at the same time taking into consideration meter proximity and telecommunications infrastructure availability.

It must be noted that the information contained in Appendix D-11 is a guideline only. Specific SMS vendors may have overcome some obstacles noted as impediments to achieving the required functionality.

5. Non-Commodity Time of Use Rates

The Minster asked the Board to address the need for and potential effectiveness of the introduction of non-commodity time of use rate structures as a means to complement the implementation of smart meters and maximize the benefits.

The charge for electrical energy (the commodity) is the single largest charge on a consumer's bill. For a typical residential consumer, the commodity charge is, on average, 45% to 50% of the total bill (before GST) depending on the time of year. The commodity portion of a consumer's bill will vary by time of use once the consumer has a smart meter and the Board's regulated price plan for smart meters is in effect.

In addition to the commodity, a consumer's total electricity bill also includes several other charges:[7]

- Delivery (transmission and distribution),
- Regulatory costs (wholesale market operations charge and, in some cases, a standard supply service charge), and
- Debt retirement charge (collected by distributors on behalf of Ontario Electricity Financial Corporation).

Each of these three charges fluctuates to some extent today as a consumer's electricity consumption increases or decreases. However, none (except perhaps for delivery charges for large consumers with interval meters) currently varies depending on when during a month a consumer uses energy.

If some or all of these non-commodity charges were levied based on time of use, the financial incentive for a consumer to reduce electricity consumption during peak periods obviously would be increased.

The remainder of this section describes how these non-commodity charges are computed today and comments on the possibility of moving to time-of-use charges in the future.

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[7] This classification of non-commodity charges is based on the bill classifications for low-volume consumers that were recently mandated by Ontario Regulation 275/04, "Information on Invoices to Low-Volume Consumers of Electricity." Electricity bills for low-volume consumers now show charges grouped into these categories. Electricity bills for larger consumers may have different groupings and more detail but the nature of the charges is the same as the charges to low-volume consumers.

5.1 Delivery Charges

Distributors bill consumers for delivery based on Board-approved rates to cover both (a) charges from transmitters to distributors for use of the high voltage transmission system, and (b) charges for use of the local lower voltage distribution system. For a typical residential consumer, total delivery charges may be 35% to 40% of the total electricity bill before GST.

5.1.1 Transmission Rates

There are two types of transmission rates to consider. Wholesale rates are those charges to distributors as measured at sophisticated metering delivery points. Retail transmission service rates are those distribution charges to consumers to recover these wholesale costs. For a number of reasons, including the difference in metering technology, retail transmission rates are different from wholesale transmission rates.

All wholesale transmission customers, including distributors, pay for transmission services based on their peak demand in a month.[8] In this respect, at least one of the components of the wholesale transmission rate can be described as time differentiated.

Retail transmission rates were always intended to be pass through charges of wholesale costs. That is, distributors would re-bill their customers, without a profit, for all of the transmission costs the distributor incurred. Because the amount of transmission costs for any month can only be determined after the month ends, distributors bill their customers at fixed rates based on estimated charges and capture any differences in a variance account.[9]

Some customers with interval meters are charged in the same manner as the distributor is charged for transmission at the wholesale level. Distributors bill transmission costs to other customers on two different bases.

- Customers with non-time-of-use demand meters (and some customers with interval meters) are charged based on the customer's peak demand (kW) during a month. This is usually a non-coincident peak demand. It is the customer's peak load in the month and is not necessarily the customer's demand in the hour in which province-wide demand is highest.

---

[8] Wholesale transmission rates charged to distributors and other transmission customers cover various services (network, connection, and transformation services) and on a per delivery point basis they are computed using either coincident or non-coincident peak demand during the month.
[9] The methodology for setting transmission rates for consumers connected to a distributor's system is set out in Chapter 11 of the Board's *Distribution Rate Handbook*.

- Customers without an interval meter or a non-time-of-use demand meter (e.g., residential and small business consumers) are charged based on total consumption (kWh) during a month.

Bill 210 froze transmission rates. The legislation has since been amended to allow the Board to adjust wholesale transmission rates. However, under the current rate freeze distributors cannot adjust the retail transmission rate to reflect a wholesale transmission price change.

5.1.2 Distribution Rates

All customers pay a fixed monthly customer charge and a variable distribution charge. The fixed charges vary by distributor. The variable charges are volumetric: demand-metered customers pay based on peak demand (kW) and all other customers are charged based on energy consumption (kWh).

In 2002, Bill 210 froze distribution rates. Distributors may not apply for rate increases without the approval of the Minister of Energy.[10] In anticipation of the freeze being removed by the government effective in 2006, the Board has initiated a project to review the revenue requirements of distributors. That project does not include a fundamental re-examination of the design of distribution rates.

5.1.3 Preliminary Assessment

A primary principle of regulatory rate design is cost causality. This principle stipulates that in a pragmatic fashion costs should be recovered from the customer who causes the costs. The unbundling of energy costs from delivery costs significantly alters a ratemaking argument for delivery rates that are time-of-use rates. This is because distribution and transmission networks are built to meet long-run peak demands. The cost causation principle, and therefore the pricing signal, in delivery rates reflect the needs of infrastructure and not supply.

This does not make time-of-use delivery charges inappropriate, but it does make them harder to design. Transmission rates currently have a time-of-use structure through the peak demand rate structures applicable to larger customers that have interval meters or non-time-of-use demand meters. If those customers reduce their peak demand through load shifting, they pay lower delivery fees.

If delivery rates can be modified with an objective of reducing load or shifting load or they could be designed to encourage reducing load. For example, wholesale transmission rates can be designed to affect the substitution of generation and transmission.

---

[10] In 2004, distribution rates were adjusted to recover the first portion of Regulatory Assets. In 2005, distribution rates will be increased to allow recover of the last 1/3 of the Market Adjusted Revenue Requirement (if distributors commit these funds to a conservation plan).

Although the Board believes the issue should be examined, it is also mindful of several conceptual and practical issues that would have to be resolved before time-of-use transmission and distribution rates could be designed and implemented. These include:

- A distributor's costs are largely fixed (at least in the short- and medium-term) because of the capital investment in wires, poles, transformers and other equipment. Compared to time-of-use rates for the commodity, it is much less certain that time-of-use rate structures for distribution services would incent consumer behaviour that has a positive impact on overall system costs.[11] This fact must be carefully considered in designing time-of-use rate structures for distribution services. A poorly designed time-of-use structure could have the effect of simply re-allocating an unequal, and arguably unfair, burden of delivery costs among consumers.

- Current rates reflect a given load diversity. Altering delivery charges to reflect time-of-use could potentially alter load diversity. Since wholesale transmission rates are calculated on a delivery point basis it is theoretically possible to create time-of-use rates that alter local peaks and create incremental and unnecessary infrastructure costs.

- With respect to transmission charges to a distributor's customers, any time-of-use rates would probably have to be linked directly to the rates charged by the transmitters themselves. If that did not occur, there might be a disjoint between what distributors pay and what they collect from consumers. Whether such a straight pass through could be accomplished or whether deferral accounts would still be necessary requires study.

- There are already several, often complex, distribution rate issues that the Board will be addressing over the next few years. Those issues stem from the way that distribution rates were initially set in 1999 and 2000 and from the rate freeze imposed by Bill 210. It is highly unlikely that designing a time-of-use rate structure can proceed as an initiative separate from the resolution of these other issues. The Board is addressing some of those issues in its project on 2006 distributor revenue requirements. Other issues will be addressed in Board projects that will affect distribution rates in 2007 and later years.

---

[11] Time-of-use rates for the commodity give consumers a financial incentive to reduce their demand in those periods when province-wide demand for electricity is high and the IMO is dispatching generation plants that have high fuel and operating costs. Significant aggregate demand response can lead to less reliance on expensive peaking plants and a reduction in overall system cost of generation. That same reduction in demand is unlikely to have any material impact on the short- or medium-term costs of distribution and transmission services.

5.2 Regulatory Charges

Under the new bill format introduced recently for low-volume consumers, regulatory charges comprise (a) a wholesale market operations charge, which is currently fixed at $0.0062 per kWh for all consumers connected to a distributor's system, and (b) a $0.25 per month service fee charged by distributors to standard supply service customers for administration of the pricing plan.

5.2.1 Wholesale Market Operations Charge

The wholesale market operations charge covers primarily various costs incurred in the wholesale electricity markets administered by the Independent Electricity Market Operator (IMO). It also includes a $0.001 per kWh charge that supports rate protection for rural and remote consumers.

There are several charges incurred in the IMO-administered wholesale electricity markets that are not captured in the hourly price of energy and that must be recovered by the IMO. There are three categories of such costs:

- Costs that vary hourly (payments by the IMO for operating reserve, congestion management, transmission line losses, and intertie offer guarantees in respect of imports of power),
- Costs that vary monthly (principally payments under contracts for ancillary services), and
- The annual operating costs of the IMO (staff, premises, systems).

Collectively, these costs are referred to as IMO "uplift." Hourly uplift is the single largest component of the IMO's uplift charge. In the first year of the wholesale market (May 2002 to April 2003), hourly uplift totalled $760 million. A large portion of that amount was incurred in three months during the summer of 2002 when there was abnormally warm weather and energy demand was very high. In the second year of the wholesale market (May 2003 to April 2004), aggregate hourly uplift dropped to $360 million.[12]

When wholesale and retail electricity markets opened in May 2002, the IMO started charging uplift to all wholesale customers, including distributors. The Board authorized distributors to charge their customers $0.0062 per kWh (to cover IMO costs and rural rate assistance) and to accumulate any difference between actual charges and the $0.0062 per kWh collected from consumers in variance accounts that would be cleared periodically.

---

[12] See *Monitoring Report on the IMO-Administered Electricity Markets for the Period from November 2003 to April 2004*, IMO Market Surveillance Panel, page 17.

By November 2002, the amount paid by distributors to the IMO greatly exceeded the amounts actually collected from distribution customers, due to much higher than expected hourly uplift payments. The balance in distributors' variance accounts was well over $100 million. Since November 2002, the amount that distributors pay to the IMO for uplift and rural rate assistance has been frozen at $0.0062 per kWh, the same amount as distributors charge their customers.[13] Since that time, differences between actual IMO uplift in any month and the amounts collected by distributors are now charged or credited to Ontario Electricity Financial Corporation (OEFC).

5.2.2 Preliminary Assessment

The IMO uplift incurred hourly is likely highly correlated with the wholesale energy price in that hour. The other underlying components of the wholesale market costs (rural rate assistance, standard service supply administration fee, and IMO non-hourly uplift) do not vary with time of use and, like distribution costs, there is no clear rate making principle which supports this form of rate design in their recovery. Addressing this issue could result in separating the current wholesale market service rates into its time-differentiated and "fixed" components. This in turns adds potentially unwanted complexity to the collection of wholesale market costs.

The Board would have to address several practical implementation issues were it to design a time-of-use rate structure for IMO hourly uplift. For example, would the time-of-use rate periods be each hour, or would they correspond to the time periods used in the Board's regulated price plan for the commodity? Would deferral accounts be necessary, and which entity would be responsible for the deferral accounts?

5.3 Debt Retirement Charge

Distributors are required to collect this charge from almost all consumers. It is set by regulation at $0.007 per kWh for most Ontario consumers and is paid to OEFC. The amount of this charge is completely independent of when the consumer uses electricity during a month. Unless the regulation were amended to incorporate a time-use charge, there is no basis for requiring distributors to bill customers on a time-of-use basis.

5.4 Billing Customers

If these non-commodity services were charged to customers on a time-of-use basis, customers would need to see and understand how their behaviour has affected their bills. For low-volume customers, Ontario Regulation 275/04 currently prescribes the items to be shown on the bill. It may be necessary to reconsider the content and format of bills for low-volume customers to make these rates effective.

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[13] Ontario Regulation 436/02, "Payments re Various Electricity-Related Charges."

6. Next Steps

The smart meter initiative is both challenging and complex. Everyone involved will need to make coordinated and committed efforts to meet the timelines and the minimum system requirements specified by government policy.

The draft implementation plan has a detailed implementation timeline identifying important tasks and milestones for project implementation over the next three years. There are several critical tasks in the first year to establish the framework for the implementation:

1. The Minister must approve the plan.
2. The implementation coordinator must be identified and processes must be set up for provincial coordination and inter-party testing, tracking, exception approval and facilitation.
3. The Board must establish the right regulatory framework. This includes amending the Distribution System Code, the Retail Settlement Code, and the Distribution Rate Handbook. The data editing and rebuilding process must be developed. Deferral accounts must be established for spending in 2005. Provision must be made in 2006 electricity distribution rates applications for smart metering system costs. If necessary, licence conditions could be amended to specify 2007 and 2010 targets. The Regulated Price Plan will establish time-dependent pricing and a timeline for implementation.
4. Distributors may undertake technology pilots to assure themselves as to the changes necessary in their own systems. These necessarily will be of rapid deployment and short duration. Distributors must also begin to develop their business processes around procurement, internal schedules and deployment.
5. Government, regulatory bodies and distributors must coordinate for a comprehensive customer communication strategy on the time-dependent nature of electricity commodity prices, the benefits of smart metering systems, the implementation plan and specific distributor approaches.

Ontario

Ontario Energy Board

Smart Meter Implementation Plan

Draft Report of the Board For Comment

APPENDICES

November 9, 2004

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Appendix A. Introduction

Appendix A-1: Directive

RECEIVED
JUL 1 6 2004

CHAIR ONTARIO
ENERGY BOARD

Minister of Energy
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Toronto ON
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Tel.: 4163276715
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JUL 1 4 2004

Mr. Howard Wetston
Chair
Ontario Energy Board
2300 Yonge Street, 26th Floor Toronto, Ontario
M4P 1E4

Dear Mr. Wetston:

Enclosed is a copy of a Minister's Directive issued under Section 27.1 of the *Ontario Energy Board Act,* 1998 recently approved by the Lieutenant Governor in Council. The Order in Council is dated June 23, 2004. The Directive requires the Board to develop and, upon approval by the Minister of Energy, implement a plan to achieve the government's objectives for the deployment of smart electricity meters. The Directive requires the Board to provide its completed implementation plan to the Minister of Energy no later than February 15, 2005.

In conjunction with the development of its implementation plan, the Directive also requires the Board to examine the need for and effectiveness of time of use rates for non-commodity charges - in addition to season/time-based standard supply service commodity rates the Board is already in a position to establish - to complement the implementation of and maximize the benefits of smart meters.

I would appreciate the Board proceeding to take the appropriate steps to implement the attached Directive.

Sincerely,

Original signed by

Dwight Duncan
Minister

Enclosure

Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigne, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, decrete ce qui suit:

WHEREAS the Government of Ontario has established targets for the installation of 800,000 smart electricity meters by December 31, 2007 and installation of smart meters for all Ontario customers by December 31, 2010.

AND WHEREAS it is desirable, through the installation of smart meters, to manage demand for electricity in Ontario in order to make more efficient use of the current supply of electricity and to reduce the province's reliance on external sources.

AND WHEREAS it is desirable that the installation of smart meters in accordance with the aforementioned targets be facilitated and supported by a regulatory framework.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.1 of the *Ontario Energy Board Act*, 1998 to promote energy conservation, energy efficiency and load management.

NOW THEREFORE the Directive attached hereto is approved

Recommended: Minister of Energy

Concurred: Chair of Cabinet

Approved and Ordered JUN 23 2004
Date

Lieutenant Governor

O.C./Decrét 1411/2004

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

The Government of Ontario has established targets for the installation of 800,000 smart electricity meters by December 31, 2007 and installation of smart meters for all Ontario customers by December 31,2010.

In order to meet these targets and to maximize the resulting benefits, I, Dwight Duncan, Minster of Energy, hereby direct the Ontario Energy Board (the "Board") under section 27.1 of the *Ontario Energy Board Act*, 1998 as follows:

1. By February 15,2005 the Board shall develop and provide to the Minister of Energy an implementation plan for the achievement of the Government of Ontario's smart meter targets. Full implementation will commence upon the Minister's approval of the Board's plan.

2. During the development of its plan, the Board shall consult with stakeholders to:
    - identify and review options for the achievement of the smart meter targets
    - identify potential barriers to rapid deployment of smart meters and address how those barriers can be mitigated
    - address competitiveness in the provision and support of smart meters, including consideration of third party providers
    - identify and address technical requirements as set out in paragraphs 5 and 6 of this Directive and additional functionality as set out in paragraph 7
    - consider the establishment of common requirements in the office and support operations of distributors in relation to smart meters, including requirements for compatibility, and for billing and reporting
    - consider measures by which and conditions under which customers can have access to full meter data in real time and assign such access to third parties
    - identify and address regulatory mechanisms for the recovery of costs, taking into account the cost savings and other benefits that will be realized (for example, timely access to detailed system usage data) by the installation of smart meters examine the need for and potential effectiveness of the introduction of non-commodity time of use rate structures as a means to complement the implementation of smart meters
    - identify and address other issues as the Board deems advisable.

3. In conjunction with its implementation plan, the Board shall also address the need for and potential effectiveness of the introduction of non-commodity time of use rate structures as a means to complement the implementation of smart meters and maximize the benefits of smart meters.

4. *In the implementation plan, priority shall be given to installation of smart meters in new homes and for customers with a demand of 50 kilowatts or more. The Board may authorize the commencement of installation of smart meters for customers with a demand of 50 kilowatts or more as soon as it deems advisable*

without further report to the Minister. The Board may also establish other implementation priorities, including different priorities for different distributors, to optimize the opportunities for and benefits of deploying smart meters.

5. The Board's plan shall identify mandatory technical requirements for smart meters and associated data systems in accordance with the following criteria:
    - A smart meter must be able to measure and indicate electrical usage during prespecified time periods
    - A smart meter must be adaptable or suitable, without removal of the meter, for seasonal and time of use commodity rates, critical peak pricing, and other foreseeable electricity rate structures.
    - A smart meter must be capable of being read remotely and the metering system must be capable of providing customer feedback on energy consumption with data updated no less than daily.

6. Recognizing the additional capability and flexibility of bi-directional communication, the Board's plan shall identify mandatory technical requirements for bi-directional communication, except in those circumstances where the Board finds the options available are impractical.

7. In developing its plan, the Board shall consider and identify additional functionality for smart meters, on either a mandatory or optional basis. Functionality to be considered includes:
    - stand-alone customer feedback (providing immediate feedback, such as usage, pricing or spending data, to the customer by way of customer display or interface)
    - load control capabilities that can be utilized either by the distributor or the customer
    - capability of multi-meter readings (for example, gas and water metering in addition to electricity metering)
    - any other functionality the Board deems advisable.

8. The Board may establish different technical requirements and functionalities for different customer groups.

(Minister of Energy)

Appendix A-2: Background

The Board has previously expressed concern about the demand/supply balance in Ontario. In its Report to the Minister of Energy, it stated that:

> "...supply is falling behind demand. Ontario is facing tight supply conditions that are expected to continue past 2007. Problems with existing nuclear plants, transmission system constraints, and lack of investment in new generating plants contribute to these conditions. Coal power that releases harmful emissions now accounts for about one-quarter of our electrical generation, and government policy direction would end this by 2007. New supply and investment in transmission are part of the solution, but cannot be built fast enough to meet our needs.... By reducing consumption and using electricity more efficiently, the province can reduce the rate at which demand is growing."[1]

The policy of the Government of Ontario is to install 800,000 smart meters by December 31, 2007 and for every Ontario consumer by December 31, 2010. The objective of the policy is to help consumers control their electricity bills though conservation and demand response. Smart metering systems are also a key tool to enable another Ministry objective of 5% savings in energy use in Ontario by 2007.

As the Board noted in the Report to the Minister of Energy:

> "...three conditions are needed to make consumers change the amount or timing of their consumption:
>
> a) a price that changes over time in response to demand and supply forces;
>
> b) the ability of consumers to see and respond to a price signal; and
>
> c) measurement of the response so that consumers get credit for their action."[2]

Dynamic Price

It is important to note that a fixed price for electricity is artificial. Electricity costs more to produce at peak times. This is more than demand/supply balancing. The plants that are necessary to produce electricity to meet brief peak demands are more expensive to run than base-load nuclear or hydro-electric plants. Price schemes that blend these costs into a fixed price mean that off-peak users are subsidizing the consumption of others. A dynamic price scheme more accurately reflects the cost of the commodity.

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[1] "Report of the Board to the Minister of Energy: Demand-side Management and Demand Response in the Ontario Electricity Sector", Ontario Energy Board, March 1, 2004, p.1.

[2] Ibid, p. 23

Currently, wholesale consumers and large, interval-metered, retail consumers pay the hourly Ontario energy price (HOEP) from the IMO-administered real-time energy market based on their usage. Large, non-interval metered, retail consumers pay the HOEP based on their accumulated usage mapped to their distributor's net system load shape.

Designated consumers[3] pay 4.7¢ per kWh on the first 750 kWh of their monthly consumption and 5.5¢ per kWh on the balance. This is an increasing block structure that attempts to put a lower price on electricity for essential needs. It is still essentially a fixed price. Since most distributors read meters and bill every two months, many distributors simply apply a 1500 kWh limit for the lower price tier.

The Board is in the process of developing a Regulated Price Plan for residential and small business consumers without retail supply contracts. The RPP is expected to be in place by May 2005. Although details are still being developed with a stakeholder working group and public comment, the Board has announced the principles in its business plan. A regulated price plan will:

a) reflect the true cost of electricity;

b) be stable;

c) be supportive of demand-response and conservation; and

d) not be a barrier to investment.

In reflecting the true cost of electricity and supporting demand-response, a regulated price at some point is likely to have a time-dependent component.

Price Response

Under any form of dynamic pricing, consumers can choose to manually or automatically change the amount or timing of their use of energy because of price signals. The response may be overnight scheduling of energy-intensive processes like pulping, steel-making, baking or laundry. Or it may be installing more energy efficient equipment for peak activities such as lighting, air-conditioning or freezers.

It is important to remember that energy use is a means to an end and that not all commercial or residential activities can be changed. Just-in-time activities, whether heating steel billets for rolling, cooking food for meals or lighting, are poor choices for load shifting. Activities that create something that can be stored for later use, such as lumber or clean laundry, are more appropriate. Equipment that is on constantly such as freezers, refrigerators or storage water tanks are opportunities for energy efficiency or peak interruptions that do not affect performance.

A price signal is the link between the dynamic price and the response.

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[3] Defined in section 56 of the *Ontario Energy Board Act*, 1998 and associated regulations.

Measurement of Response

Accurate and timely measurement is important to ensure that a consumer gets credit for changing the amount or timing of his/her electricity consumption. Otherwise, as with the original spot-market pass-through based on net system load shape, some consumers will be under rewarded for their activities and some consumers will see undue benefit.

Advanced metering technology is important to enable demand response in the retail market. However, debate exists on what meters are appropriate for various consumer groups and when/how they should be deployed. The Board notes that meters are a tool, and without pricing changes and the ability to respond, meters alone are not sufficient to help consumers change their behaviour or control their electricity bills.

A smart metering system is at a minimum capable of reporting usage according to predetermined time criteria. This could include time of use or interval meters. In addition, smart meters may be connected to a remote or automatic meter reading system that may or may not feed into a feedback system for consumption and spending on a real or close-to-real time basis. They may have bi-directional communication allowing them to receive signals that change the time criteria, change the tariff, control external devices, etc.

A. Current Requirements

The Distribution System Code of the Board calls for a metering inside settlement time (MIST) meter for any new distribution customer with an average monthly peak demand during a calendar year of over 500 kW and any existing distribution customer over 1000 kW. The DSC also requires a distributor to install an interval meter (either MIST or metering outside settlement time) for any customer who requests one. The customer pays the full incremental cost.

Non-OEB-licenced generators (those whose generation is entirely for self-consumption) are metered in the same manner as any other load.

According to the Retail Settlement Code of the Board, interval meter data must be used to calculate settlement costs (section 3.3.1). Retailers must have access to current, interval data for either a billing period or 30 days through the Electronic Business Transaction system (s. 11.1). Interval consumers must have access to interval data by EBT system, direct access or printed on the bill (s. 11.2). Customers can have the right to interrogate their meter or to assign that right to a third party (s.11.2). This allows customers to read their meter directly rather than use distributor data. Consumers can request in writing that historical usage date be provided to third parties (s. 11.3).

B. Smart Metering System Impacts

1. Benefits for Customers

The primary objective of the Government policy on smart meters is to give consumers more control over the energy part of their electricity bill. Smart meter technology enables consumers to pay the actual price for the electricity at the time that they actually use it.

A fixed price for energy averages out the market costs for the electricity dispatched to meet load at high and low priced periods. If prices are dynamic but use is accumulation metered, then a consumer's use is mapped to a net system load shape. An individual consumer pays for his or her use based on the aggregated use pattern of similar consumers.

When individual use is interval metered, a consumer who normally uses less energy in peak times and/or can shift more use into off-peak times will pay less for energy. Conversely, a consumer with more on-peak use will pay more. By controlling use, both types of consumer have the opportunity to control their bills.

In a study conducted for EA Technology, the authors concluded that for residential applications:

> "Better billing feedback produced savings of up to 10% in electrically heated homes in cold climates, mainly using simple manual methods. In the absence of electric space heating, smaller savings are likely, but some of the automatic measures here [in the U.K.] could produce new types of saving - for example in refrigeration - which would not be possible manually. Load shifting is easier than load reduction so cost savings are easier to achieve than energy savings, but both would probably lie in the 0 - 5% range for a home without electric heating."[4]

It is important to note that consumers who use more peak energy will pay more for the same amount of electricity. This will include schools, hospitals and residential consumers with electric heat. Some of these consumers will take action to lower their bills. Demand-side management (DSM) programs could be targeted to vulnerable consumers with poor access to capital to help them act. Studies have shown that the fuel poor[5] do save when smart meters are used but it is not clear if that is at the expense of their comfort.[6]

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[4] "A review of the energy efficiency and other benefits of advanced utility metering", A.J. Wright et al. for EA Technology, April 2000, p.16.

[5] Ofgem defines households as "fuel poor" if, in order to maintain a satisfactory heating regime, they would need to spend more than 10 per cent of their income on all household fuel use.

[6] Ibid., "A review of the energy efficiency and other benefits of advanced metering", p. 2.

The Board is currently administering a process by which the local electricity distribution companies of Ontario may spend up to $225 million on conservation and demand management activities. The Board is also developing a sustainable framework for distributor activities allowed under Ontario Regulation 169/99 to section 71 of the Act:

(a) the promotion of electricity conservation and the efficient use of electricity;

(b) the provision of electricity and load management services; and

(c) the provision of services related to use of cleaner energy sources.

The framework is being developed in conjunction with 2006 electricity distribution rates.

2. *Benefits for the System and the Market*

Another primary objective of installing smart meters is to decrease Ontario's overall peak demand. When the system peak is lowered and the system is operating at less than capacity, then:

(a) reliability is improved;

(b) required capacity is lower (all other factors being equal);

(c) system losses are lower;

(d) less congestion management is necessary; and

(e) uplift charges are lower.

When consumers take action to shift energy use to off-peak periods, the demand peak will be lower, but off-peak demand will rise. See Figure 1.

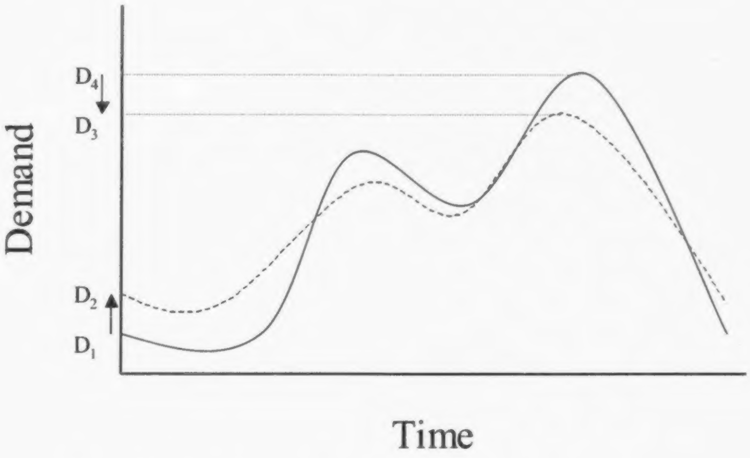

Figure 1: Demand curve changes with shifted load

The price of the resources to meet the increased demand in off-peak periods will be higher. Even so, the nature of the price-demand curve likely means that the price increases in off-peak periods are likely to be less than the price decreases in peak periods.[7] See Figure 2. Overall, the total cost to the market to meet all demand should be lower.

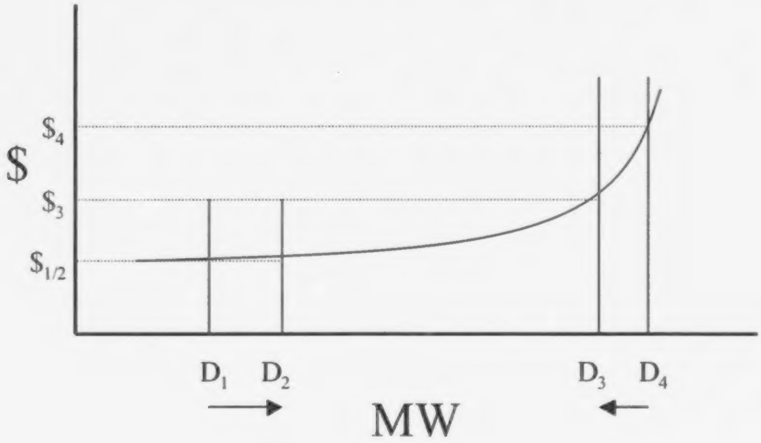

Figure 2: Electricity Price/Demand curve for shifted load

3. *Benefits and Risks for Generators*

When the system peak is lower, some high-margin peaking plants may end up being dispatched fewer hours. When the off-peak demand is higher, some base and intermediate plants will be dispatched more often. In a competitive generation market, these risks and benefits are borne by the shareholder of the asset.

4. *Benefits for Retailers*

Retailers may benefit in two ways. They can structure an offering to a consumer based on a true consumption profile. Also, they can mitigate their risk by tying the offer to load control services. In this way, they avoid buying energy at peak periods and control their costs.

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[7] "Mandatory Rollout of Interval Meters for Electricity Customers: Draft Decision" Essential Services Commission, March 2004, p. 49.

5. *Benefits for Distributors*

Depending on the system installed, the distributor could have many benefits:

(a) lower meter reading costs;

(b) theft and tamper detection;

(c) account automation leading to fewer customer disputes;

(d) fewer estimated bills;

(e) true reads on customer change;

(f) improved bill collection; and

(g) broader application of time-of-use distribution rates; including the potential to apportion system losses to the cause.

However, any activities that tend to decrease overall distribution throughput compared to what was used to determine revenue requirement may affect a distributor's revenue.

Appendix A-3: Working Groups

Smart Metering ***Metering Technology Working Group*** **Participants:** Bluewater Power Distribution Corp. Chatham-Kent Hydro Hydro One Networks Inc. Independent Electricity Market Operator London Hydro Measurement Canada Oakville Hydro Energy Services Peterborough Utilities Services Inc. Toronto Hydro-Electric System Ltd. Woodstock Hydro Services Inc.	**Smart Metering** ***Communications and Data Interface Technology Working Group*** **Participants:** Elster Metering Enersource EPCOR Utilities Inc. Hamilton Hydro Inc. Hydro Ottawa Limited Itron Olameter Inc. OZZ Energy Solutions Inc. PowerStream Inc. School Energy Coalition The SPI Group Inc. Toronto Hydro-Electric System Ltd.
Smart Metering ***Planning and Strategy Working Group*** **Participants:** BOMA Collus Power Corp. Direct Energy Electricity Distributors Association Energy Probe Research Foundation Hamilton Hydro Inc. Hydro One Networks Inc. Demand Response Coordinating Committee IBM Milton Hydro Distribution Inc. Power Workers' Union Toronto Hydro-Electric System Ltd.	**Smart Metering** ***Cost Considerations Working Group*** **Participants:** Burlington Hydro Inc. Cambridge and North Dumfries Hydro Consumers' Council of Canada Enbridge Gas Distribution Halton Hills Hydro Hydro One Networks Inc. London Property Management Association Newmarket Hydro Ltd. RODAN Meter Services Inc. Veridian Corporation

Appendix B. Implementation

Appendix B-1: Alternatives to Metering Remaining as a Regulated Distribution Function

Issue Statement: Should the provision of metering no longer be a regulated distribution function?

Options:

A number of options were considered in this analysis with the objective of lowering metering costs, increasing customer choice and responsiveness. Options that included meter contestability without a default meter service provider were analyzed but not included because large customers during the consultation process were not in favour of being required to own their meters but wanted the option to own them. This meant that an entity (likely the distributor) would still have to take on the role of a default meter service provider in a contestable model.

Option 1:

- Mandate that all distributors provide any customer >50kW with the option of owning his own meter
- Distributors would be responsible to be the default meter service provider for all customers in their territory
- A customer who chooses to own his own meter would be responsible for purchasing the meter (basic or enhanced functionality) and to contract with a registered meter service provider (MSP) to provide meter installation and maintenance

Option 2:

- Mandate that all distributors transfer legal responsibility for metering in their territories to a new provincial regulated entity
- The new regulated entity would be responsible for owning, installing, maintaining and reading the meters along with managing the meter data to hand-off to the distributor
- The third party may have plans to leverage the infrastructure to obtain a higher ROI than the distributor would be able to obtain and would be able to consolidate the needs of the province to obtain a higher utilization on the infrastructure and systems to reduce overall costs

Option 3:

- Allow distributors to choose for themselves whether or not they would like to set up contestability within their service territory to allow non-wholesale participant customers the option of owning their own meters

- Distributors would be responsible to be the default meter service provider for all customers in their territory

Option 4:

- Legal responsibility for metering remains with distributor (i.e. meter service remains a regulated distribution function)
- Large customers (>50 kW)are allowed to select enhanced functionality for metering and can request an earlier installation date for meters within specified guidelines
- Performance standards are established for distributors with respect to turnaround on requested installations
- The distributors have the latitude to engage in meter supply contracting as they do currently and the distributors continues to have the legal responsibility for metering as they do today.
- Small customers would remain with the distributor's standard offer for metering
- All customers would be free to select a competitive supplier for services above and beyond metering services (e.g. direct load control)

Background:

Contestable supply of metering occurs when a distributor loses its monopoly over metering (i.e. metering other than the default meter service cease to be a regulated distribution function) and third parties can obtain the legal responsibility for metering.

To have the legal responsibility or obligation for metering, allows the entity, subject to relevant regulations, to:

- decide how and where the meter will be deployed;
- have access to the meter;
- provide adequate security and protection for the meter;
- charge another party for using the meter;
- be responsible for applicable (Owner, Contractor) Measurement Canada requirements with respect to meter
- sell and receive the proceeds from the sale of the meter

There are 3 industry groups that are supportive of contestable supply of metering in order to achieve certain goals:

1. **Customers >50kW:**

   This customer segment would like to have the ability to choose its own meter functionality and not have it dictated by distributors. They also feel that distributors do not have the capability for mass meter deployment based on their experience to date in requesting interval meter installations. Requests have been met with considerable delays and in some cases refusals due to lack of distributor resources. They feel that making metering competitive will bring in more responsive MSPs that will be able to better fulfill needs in this customer segment. Large customers are not generally predisposed to owning the meter. Rather, they seek alternative MSP arrangements to meet needs which may not be accommodated by distributors.

2. **IMO:**

   The IMO is supportive of a viable and robust MSP sector. They believe that by opening up the retail market to meter supply contestability, more MSPs could enter the market, compete for business which would result in more innovation, lower prices, and greater value to consumers.

3. **Metering Service Providers:**

   MSPs would like to see the retail market open up to contestable supply of metering not only for electricity, but for natural gas, and other pipe commodities such as water/wastewater. They feel that this would facilitate one meter service provider at a facility or home and would drive down the cost for customers.

The main opposition to contestability comes from distributors:

> For distributors, the meter is their cash register and is used to clear the market. It is central to their operations and would result in significant business risk if problems arose from making it contestable. In addition, it is the distributor's responsibility to connect consumers to the grid. The meter is the final part of that connection. Adding a third party would add complexity in business processes because of additional interface points. Distributors would also be wary of being left with the high cost, hard to access meters as default suppliers of metering. Many distributors currently use third parties under contract to provide certain metering services and feel that this is a preferred option to meter service contestability that still allows distributors to effectively manage their business risks.

Other Jurisdictions:

The information that was available to the Board about the experiences of other jurisdictions was anecdotal in nature. There was little quantified analysis available to validate the experiences of other jurisdictions or Ontario's wholesale market. The anecdotal evidence in US jurisdictions has been that competitive supply of metering has not lowered costs to the consumer. The switching rate of customers away from the distributor had been very low, and many third parties that owned meters are contracting services from the distributor. It has resulted in slower deployment and penetration of smart meters as distributors have been reluctant to invest in their own metering fleet. In contrast, there is a view in Ontario that competitive supply of metering in the wholesale market has reduced costs considerably.

Implementation Issues:

Distributor Issues:

- Metering costs are currently embedded in the rates. Distributors would have to adjust their rates if a third party is to provide metering service to consumers.
- Allowing a third party to provide the service adds another billing line item which may be viewed as contrary to the most recent changes required by the Government to bill prints in its attempt to minimize the number of line items.
- Allowing a third party to provide metering service to consumers would require collection of metering costs and pass through arrangements to the third party. OEB rate approvals may be required for separate meter provision charge.
- Settlement issues regarding late payments, and unpaid bills would need to be worked out (e.g. who gets paid first in the event that a customer provides partial payment?).
- Who purchases or pays for the existing assets that will be declared stranded once new metering requirements are in place.

Customer Issues:

- Most small customers do not differentiate between the supplier of electricity and the supplier of the meter. Separating the functions could add confusion at a time when the industry is already seen as confusing.
- Some customers would like to have specific metering services or metering functions made available which are outside of the "standard" offering of the distributor (power quality monitoring, etc.).
- Customers who purchase power from retailers may wish to have the meter provided by the same entity.
- Customers may be upset if they perceive that adding new meter suppliers is a new cost. For example, customers always paid for industry debt but were unaware of the fact until it became a new line item on the bill.
- If a party other than the distributor owns the meters, this may become a barrier for the customer to switch retailers

Retailer / Aggregator Issues:

- Some retailers or aggregators may wish to have specific meters that are outside of the standard offering of the distributor.

- Retailers and aggregators have expressed interest in obtaining customer usage data closer to real-time. Owning and reading the meter would give them this opportunity.
- Retailers may wish to own the meter and control the communications platform for metering in order to piggyback other services such as load control.

Vendor Issues:

- Some vendors would want to sell both the product and the service as systems integrators
- Vendors may not wish to take on the risk of customer non-payment for settlements because of lost or inaccurate meter data. Contracts with distributors would become important to ensure liability for "lost data" is appropriately apportioned.
- Vendors have stated in their submissions that they would prefer to deal with fewer rather than more purchasers. Adding more meter providers would be contrary to these statements as long as distributors are forced to provide services to "default" consumers.

IMO Issues:

- IMO issues are mainly tied to wholesale metering, and would likely only be involved if it is felt that adding more meter providers would increase availability of MSP services to wholesale market participants.
- IMO may be concerned if settlement issues from private meter companies cause delays in clearing the market.

OEB Issues:

- OEB would need to establish and enforce a Metering Code that establishes an MSP's responsibilities.
- OEB would need to be granted regulatory authority over meter service providers in order to regulate costs and timely provision of service.
- OEB would need to assess the impact (positive and negative) of private suppliers on existing distributor rates.
- Enabling customer choice in the meter service provision would further fragment the metering technologies deployed in the province and reduce economies of scale.

Summary of Discussion / Analysis:

Innovation, customer responsiveness and efficiency are goals that should be achieved in the metering area. The question is what is the most cost effective way to achieve these improvements and still be able to achieve provincial targets for smart meter implementation?

Options that eliminate the distributor monopoly would likely drive more innovation as third parties may choose to experiment in new market offerings while the distributor's regulator would likely demand investment in proven technologies to limit risk.

For Options 1 and 3, the distributor would remain the default meter service provider. Although the Board did not have any analysis that showed the additional costs for distributors to become default meter service providers in a contestable meter supply model, it was felt that due to the need for redundant processes, systems, inventory along with new interface points with third parties, costs to the customer would go up significantly. From the benefit point of view, the Board did not have any analysis that showed that benefits from innovation and customer responsiveness would be sufficient to justify the additional distributor costs for these options and anecdotal evidence of experiences in the US showed that customers did not receive the anticipated benefits of lower costs.

Option 2 could result in better use of the new infrastructure by a third party and the proceeds from the sale of the monopoly could be used to pay for stranded assets. Any sales of distributor assets related to the implementation of this option would require OEB approval as all distributor asset sales require OEB approval. In addition, all union staff would need to be transferred with the sale of the assets to the third party service provider (under the *Ontario Labour Relations Act* (section 69(2))

From an implementation timeline perspective, both options 1, 2 and 3 would require that new regulated entities be set up and that federal laws such as the *LMB-EG01 Act* be changed in order to eliminate the distributor's legal responsibility for metering. With the already tight timelines imposed by the provincial targets, the Board felt that setting up new regulated entities and modifying regulation would delay a much-needed early start to the initiative. As well, with more entities involved in the procurement and installation processes there was a greater likelihood that economies of scale would not be achieved and the price per point for smart meters would go up.

By keeping legal responsibility for metering with the distributor whose costs are already regulated by the OEB as in option 4, distributors could have performance standards imposed on them related to metering service provision. Although possibly less effective than competitive pressure on costs, benefits could be achieved without distributor divestiture (e.g. through meter supply contracting).

Recommendations:

Option 4 is recommended (i.e. metering service remains a regulated distribution function). To address possible issues related to the non-contestability of meter service such as the early installation of smart meters for consumers looking for the expeditious deployment of smart metering functionality, general service customers >50kW will be allowed to request to have their meters installed prior to their deployment schedule but after the communications infrastructure for their area has been decided and subject to meter availability. Customers requesting early installations will not incur any additional charges except if they request enhanced meter functionality or off-hours installation. Distributors will be mandated and held to compliance to provide a 4-6 week turnaround on meter requests (subject to meter availability tied to procurement strategy) except for extraordinary circumstances. Early installation will also be contingent on the customer meeting all conditions required for the distributor to be able to access the meter location and perform the installation. Conditions include, but are not limited to: clearing of path to the meter by the customer; distributor access to meter room; distributor entry to the building; customer agrees to power outage and conditions of service are satisfied. The OEB should define performance standards as part of the changes to existing regulatory guidelines on service quality indicators. In the event that distributor non-compliance to requests becomes problematic, the OEB should revisit the issue of contestability as a possible solution.

As a result of the mass deployment approach recommended for general service <50kW and residential customers, early installation requests should not be accommodated for these customer segments.

The recommended option would not restrict distributors in engaging in meter supply contracting including leasing arrangements subject to their collective bargaining agreements.

Appendix B-2: Provincial Coordination and Distributor Compliance

Issue Statement: How should provincial implementation of smart metering be coordinated? How should distributor compliance be structured to ensure that provincial targets are met?

Options Analyzed and Rationale for Recommendation:

The following table shows the key issues that were discussed related to provincial coordination and distributor compliance. For each decision, options were identified, analyzed and a recommendation provided.

Decision	Options Considered	Recommendation	Rationale
Who Should take on responsibility for provincial coordination?	1. OPA 2. Distributors self-comply	Option 1	OPTION 1: + Takes advantage of an existing compliance process and organization + Provides early warning of provincial targets in jeopardy OPTION 2: + lower regulatory costs - No early warning of provincial targets in jeopardy

Decision	Options Considered	Recommendation	Rationale
How should interim targets be set?	1. OEB mandated interim targets 2. Distributors recommend plan with yearly targets approved by OEB (Distributors can combine yearly targets within procurement plan while adhering to priority installations) 3. Distributor recommending plan approved by OEB (each distributor meets 2007 and 2010 targets individually)	Option 2	OPTION 1 + Higher distributor buy in + Allows flexibility and cost effective deployment OPTION 2 - does not account for distributor specific work management issues (e.g. seasonal workloads, existing resources)
How often should the distributor report to the implementation coordinator?	1. Distributors report semi-annually 2. Distributors should report to the implementation coordinator and the OEB on a quarterly basis	Option 2	OPTION 1 and 2: + identical reporting provided to both OEB and the implementation coordinator reduces the reporting workload on distributors OPTION 1: - may not be a sufficient early warning signal
What incentives should be offered to the distributor for compliance?	1. No incentives other than what currently exists 2. Incentive tied into PBR regime, triggered by exceeding targets (>110% of meters / cost under budget)	Option 1	OPTION 1: + no additional cost to customer - no incentive for early meeting of targets and reduces customer opportunities OPTION 2 + In line with current regulatory trend - Perception that customers pay more if incentives paid out

Decision	Options Considered	Recommendation	Rationale
What penalties should be laid on distributor for non-compliance?	1. Levy fines, revoke licenses and possibly implementation coordinator steps in – except for uncontrollable situations (e.g. labour strikes, vendor issues) 2. Penalty tied into PBR regime, triggered by a distributor not meeting an annual target (<90% of meters / cost over budget)	Option 1	OPTION 1: + easier to administer allowing OEB judgement OPTION 2: + In line with currently regulatory trend

Appendix B-3: Preliminary List of Implementation Tasks

Implementation Coordinator - Provincial Coordination

- Organizational structuring
    - Appoint implementation coordinator
    - Appoint industry taskforce chaired by implementation coordinator
- Establish steering committee
    - Implementation coordinator involvement / responsibilities
    - OEB involvement / responsibilities
    - OPA involvement / responsibilities
    - CRTC involvement / responsibilities
    - Distributor involvement / responsibilities
    - EBT steering committee representative involvement / responsibilities
    - ESA involvement / responsibilities
    - Measurement Canada involvement / responsibilities
    - IMO involvement / responsibilities
    - Ministry of Energy involvement / responsibilities
- Central design coordination
    - Establish working groups to design detailed specifications for industry
    - Identify baseline across central agencies (more of an issue if not just OEB codes)
    - Establish and execute change control of baseline design documents
- Develop business processes and systems for implementation coordinator
    - Develop monitoring process and systems
    - Multi-party communications processes and systems
- Distributor monitoring
    - Monitor of meter and AMR installation and workplans
    - Review distributor procurement plans for prudency and approve
    - Evaluate business cases for enhanced functionality
    - Distributor compliance processes
    - Review distributor proposals for exceptions (smart meters will not be installed)
    - Distributor monitoring against performance standards set for self-selection by large customers
- EBT Hub Monitoring
    - Conduct readiness test on existing hubs to ensure readiness
    - Conduct readiness test on MDMAs to ensure readiness
- Coordinate inter-party (distributor, retailer, EBT hub, customer) test coordination
    - Develop overall industry test strategy and design
    - Develop end-to-end test scripts
    - Test execution and results

OEB - Regulatory Document Changes

- Coordination of rules, codes and standards across different external agencies
- Bill 100
    - Legislation needs to receive third reading
    - Regulations regarding settlements need to be passed
- Changes to Distribution System Code
    - Timelines for distribution of meter
    - Standards for estimating and rebuilding of data (E&R)
    - Which customer gets which meter
    - Customer requests for smart metering
    - Disallowing meter requests for small customers
    - Communications infrastructure used for metering
    - Meter data access for customers - web, pulse, self reading
    - Meter data access for others
- Conditions of Service
    - Must be updated to meet changes in DSC & RSC
    - Meter access agreement
- Changes to Retail Settlement Code
    - Meter data access issues need to be addressed
    - NSLS calculations
    - Interval meter data settlements (current requirement to settle on HOEP)
- Changes to Affiliate Relationship Code
    - Issues with additional services
    - Issues with sharing of communications facilities (if installed)
- Plans and Processes for Recovery of Costs
    - If costs recovered from Rates
    - If costs paid by customers
    - If cash forwarded by government
    - Cost retrieved from OPA
    - Recovery of costs to customers who paid for interval meters prior to program
    - Treatment of stranded assets
- Distribution Rate Handbook
    - Changes to service quality performance standards with respect to response to customer requests for meters
- Establish Meter Data Transfer Standards (to Retailers, OPA, Customers)
    - Make changes to EBT standards for meter data provision to accommodate smart meters
    - New standards for meter data transfer to be established
    - Change in timing of meter data provision to retailers
    - If central repository proposed
    - Where are meter records kept and exchanged
    - Passing of TOU information

Provincial - Customer Communications

- Prepare detailed plan - proactive communications
    - Ministerial announcement
    - Mass communications
    - Bill stuffers / householder
    - Distributor targeted communications
    - Install communications
    - Follow-up
- Prepare detailed plan - reactive communications
    - Launch of pricing for those with smart meters
    - Technology failure issues
    - Cost issues
    - Opposition questioning
    - Access issues
    - Media activism
    - Execute communications plan

Distributor - Procurement

- Review OEB minimum requirements for meters and communication
- Develop individual distributor technology requirements for meters and communications
- Create or leverage existing distributor buying groups for procurement
- Determine logistics plan for buying group (warehousing, sealing, delivery, returns)
- Invoicing procedures
- Deployment coordination among distributors
- Delivery procedures
- Estimate point volumes for different technology requirements
- Develop RFP Document
    - Commercial terms and conditions
    - Convert standards and individual distributor requirements to purchasing specifications
    - Customer / territory technology issues
    - Warranty
    - Installation
    - Price points based on volumes
    - Financing options
    - Deployment schedules
    - Penalties / incentives
- Conduct RFP Process
    - Determine RFP process
    - Determine number of vendors to be awarded per technology type
    - Identify suppliers to participate in RFP
    - Conduct RFP process
    - Evaluate RFP responses
    - Negotiate contracts
- Submit procurement plans to implementation coordinator for Approval
    - Buying groups involved
    - Methods used to obtain economies in scale in procurement, logistics, sealing and installation
    - Estimated costs
    - Number of technologies to be chosen
- Contracting for Meter Services
    - Analyze outsourcing options
    - Analyze joint distributor service arrangements for meter services

Distributor - Business Process Design

- Meter reading
    - Check reads
    - Cycle reads
    - Final reads
    - Transition to AMR
- Meter data management
- Meter data E&R
    - Edit
    - Estimate
    - Maintain standards
    - Audits
- Data collection
    - Data security
    - Data Storage
    - Backup
- Access to meter data
    - Customer
    - Retailer
    - OPA
- Settlement calculations
- Bill preparation and presentation
- Bill and collections
- Meter shop processes
    - Coordination with other utilities (gas, water)
- Meter installation
    - Special meter requests
    - Meter registration
    - Account setup
- Reverification
    - Sampling
    - Compliance reporting
- Meter servicing
    - New certifications
    - New test equipment
    - Meter repair
    - Communications maintenance
    - Customer inquiries
- Call center processes
    - Scripts
    - Customer audits on bill disputes / customer service
- Provincial reporting requirements
    - Progress and issue reporting
    - Cost and benefit reporting
- Enhanced functions and processes
    - Load control
    - Power quality
    - Outage management
    - System planning
    - Net billing
    - System operations
    - Disconnect / reconnect
    - Tamper detection
- Communication infrastructure
    - Maintenance
    - Other
- Distributor interface with retailers
    - Receipt of consumption and TOU data
    - Timing / content of information sent to EBT Hubs
    - Service transaction requests
    - Settlement processes due to change in EBT transactions

Distributor - Design and Develop Systems

- Assemble team (internal and external resources)
- Design IT solution architecture
  - Meter reading system
  - Complex billing engine
  - Meter data management system
  - Customer information system
  - System components for enhanced functionality
  - Retail settlement service provider interface
  - EBT interface
  - Interface with work management system
  - Interface with asset management system
- Build systems
- Decommission obsolete systems
- Make fixes identified in testing

Distributor - Testing

- Involvement in provincial testing
  - Technology pilots by distributor early adopters
  - Inter-party (distributor, EBT hub, customer, retailer) testing
- Individual distributor testing
  - Develop test scripts
  - System testing
  - Integration testing
  - User acceptance testing
- Cutover
  - Rates and other data populated
  - Systems migrated to production environment
  - Contingency planning and workarounds

Distributor - Change Management

- Documentation
  - Business processes
  - Policies and procedures
  - System documentation
- Performance Metrics
  - Internal and external service level agreements (metrics and targets)
- Training
  - User training
  - Support staff training
- Staffing changes
  - Staff redeployment (based on collective bargaining agreements)
  - New staff position postings, hiring processes, reporting relationships

Distributor - Meter and Communications Infrastructure Deployment

- Consider policy decisions on meter relocation for access
- Develop deployment strategy and schedules based on prioritization plan
- "Develop logistics plan (warehousing, cross docks, deliveries with vendor)"
- Create vendor specific installation plans
- Secure installation labour
- Develop field installation and verification process
- Train field staff on installations and verifications
- "Deal with exceptions (no access, tampering, etc.)"
- Order and warehouse equipment
- Complete work program
- Register assets

Appendix B-4: Procurement Strategy

Issue Statement: How should required equipment and installation services be procured for the province-wide deployment of smart metering?

Options:

The following table outlines three options that were developed and analyzed to come to a recommendation.

Components of Procurement Strategy	**OPTION 1:** **Distributor Procurement**	**OPTION 2:** **Centralized Provincial RFP to Multiple Vendors**	**OPTION 3:** **Centralized Provincial RFP to a prime contractor**
Group size	Distributor buying groups (like minded with similar needs)	All distributors	All distributors
Distributor responsibilities	• Submit procurement plans for implementation coordinator approval to demonstrate prudency prior to contracting • Submit business cases for additional requirements if rate recovery is requested • Purchasing, logistics and deployment • Report implementation progress to implementation coordinator	• Distributor taskforce is formed and puts together province wide requirements list to include in RFP process • Submit business cases for additional requirements • Assist in evaluating RFP responses and awarding vendors • Deployment planning, installation and contracting	• Distributor taskforce is formed and puts together province wide requirements list to include in RFP process • Submit business cases for additional requirements • Assist in evaluating RFP responses and awarding vendors • Deployment planning, installation and contracting

Components of Procurement Strategy	**OPTION 1: Distributor Procurement**	**OPTION 2: Centralized Provincial RFP to Multiple Vendors**	**OPTION 3: Centralized Provincial RFP to a prime contractor**
Implementation coordinator responsibilities	• Provide minimum requirements • Facilitate the creation of buying groups where groups do not exist • Approve buying group procurement plans and business cases (if cost recovery is needed)	• Facilitate process using distributor taskforce • Coordinate requirements gathering, contracting, high level logistics and warranty • Repeats process over time and specifies new technology add-ons • Manages contracts	• Oversee deployment and logistics • Specifies new technology add-ons over time and manages contract scope changes
What functions will be contracted for?	• Meter • Communications • Logistics / Warehousing • Installation • Meter Data Services	• Meter • Communication • Logistics / Warehousing	• Meter • Communication • Logistics / Warehousing
Contracting Agent	Individual distributors or buying group if legal entity	Individual distributors	Individual distributors
Number of contracts awarded	Multiple vendors	Multiple vendors	Single – Prime contractor provides list of vendors
Timeframes	Multiple processes	Multiple processes	Single year process with options changing over time
Distributor risk of non-compliance	Fully on distributor for all aspects of project	Falls on central agency, distributor risk on execution only	Falls on central agency, distributor liability on execution only

The option of a central buying agent that is the contracting agent and would be responsible for logistics was discussed and dismissed because it would be outside of the OEB's or OPAs existing competencies and would not meet many of the established criteria for options (as outlined in the background section).

The option for a "Made in Ontario" solution, where technology would be developed specifically for Ontario that worked for all meters in the province and would be manufactured in the province, has many benefits. It would create jobs in Ontario, ensure an appropriate level of rationalization and would achieve economies of scale. But it would require years of upfront analysis and development and would not be possible in the timeline specified by the Minister. It would also place additional risk on the province and would likely require additional approvals by Measurement Canada.

Background:

Currently, many distributors are associated with buying groups for the purchase of many of their equipment purchases. Besides purchases, some groups have also developed common policies, common DSM initiatives and training. Three examples of buying groups are listed below that together already account for more than 1/3 of the utilities in the province.

NEPPA Group (Niagara Erie Public Power Alliance)

Consists of Haldimand County, Niagara Falls, Niagara on the Lake, Norfolk, Brant County, Grimsby, Peninsula West, St. Catherines, Welland, Canadian Niagara Power and Branford.

CHEC Group (Cornerstone Hydro Electric Concepts Association)

Consists of Center Wellington, Collus, Grand Valley, Gravenhurst, Innisfil, Lakefront Utilities, Lakeland Power, Midland Power, Orangeville, Orillia, Parry Sound Power, Rideau St. Lawrence, Wasaga, Wellington North, Westario, West Coast Huron, Woodstock, North Bay and Erie Thames

Upper Canada Energy Alliance

Consists of Power Stream, Newmarket, Innisfil, North Bay, Orillia, Parry Sound and Tay.

It is estimated that at least 70% of distributors are part of a buying group, some larger than others. Some utilities are members of multiple groups. The majority of distributors in buying groups are small to medium sized utilities.

With the huge numbers of advanced metering technology planned to be deployed in Ontario, the Ministry of Energy, OEB and distributors will want to select a procurement option that achieves the following: low overall cost to the consumer; manageable implementation risk; respects distributor historical responsibilities; able to be implemented within government timelines; minimizes cost of customer transfers (load transfer resolution, boundary adjustments, mergers and joint ventures); encourages innovation and economic development and enhanced functionality options are not precluded by process.

Other Jurisdictions:

Most of the mass deployments in other jurisdictions were completed in territories that were covered by either a single distributor or a few distributors. Many of these deployments were championed by the distributor itself. In terms of achieving economies of scale, the other large implementations demonstrate the cost savings that can be achieved by high volume purchases. The challenge that Ontario faces that has not been present in most other implementations is the deployment across 90+ distributors.

Implementation Issues:

Distributor Issues:
- Distributors would like the flexibility to be able to leverage technologies (e.g. fibre) or specific opportunities (e.g. multi-utility installations) in their territories
- Distributors need to have assurance that the substantial costs associated with smart meter deployment will be recoverable through rates.
- If distributors are provided the flexibility to organize their own deployments, they will be able to combine small metering installation work with other utility work activities or other DSM initiatives to reduce installation costs

Customer Issues:
- Large customers who are anxious to receive smart meters will want a process that will place clear accountability on distributor to deliver on their responsibilities

Retailer / Aggregator Issues:

- Retailers will want to see that the procurement process will not preclude enhanced functionality through submitted business cases so that load control and other features will be able to be added on.

Vendor Issues:

- Some vendors would be worried about being entirely shut out of the Ontario market with a central provincial RFP process (decentralized procurement would reduce this risk)
- The sales effort savings of options 2 and 3 would be reduced as vendors still need to negotiate technologies and delivery timetables with individual distributors
- In order for vendors to be able to pass cost savings to distributors from economies of scale, orders must minimize: shipments to different locations; distributor specific labeling of meters; meter programs; and the number of vendor invoices.

IMO Issues:

- None

OEB Issues:

- OEB would like some assurance that procurement throughout the province will be carried out in a manner that minimizes costs
- OEB would need to develop its internal competencies in mass procurement if central procurement is recommended and the OEB is appointed the responsibility of implementation coordinator
- A cost allocation method for allocating central contract costs among distributors would need to be determined

Summary of Discussion / Analysis:

The following table summaries the pros and cons of each option.

Components of Procurement Strategy	OPTION 1: Distributor Procurement	OPTION 2: Centralized Provincial RFP to Multiple Vendors	OPTION 3: Centralized Provincial RFP to Prime Contractor
Pros	• More flexibility over ultimate number of technologies chosen (assuming minimum requirements are met) • Allows for the development of joint business cases • Allows for future innovation (through procurement over multiple years) • Allows distributors to participate with like minded distributors (with similar requirements) • Will reduce technologies chosen vs. 90+ selections • Staged procurement allows for business case development for future lots • Places full responsibility on the distributor • Distributors may be able to leverage existing distributor buying groups and cross-distributor service arrangements	• Greatest chance to obtain volume discounts (economies of scale) • Full knowledge of number technologies of technologies to be chosen for the entire province • Maximizing uniformity in technology installed across the province will help in technology rationalization in the future • Reduced risks to distributors • Possibility of central logistics planning for province to reduce inventory and establish optimal staging locations • Delivery compliance, product quality, vendor contract disputes all dealt with by one entity increasing leverage of vendors • Equal importance attached to small and large distributor needs • Reduced reporting requirements on procurement process from 90+ distributors • Allows for better control of distribution of supply to meet provincial implementation plan	• One stop shop (point person to go to for all issues) • Off-load some of the risks to the prime contractor (depending on how contract is structured) • Prime contractor could provide centralized logistics, warehousing and delivery • Increases financing available to smaller, innovative firms that are part of the vendor's offerings • Increased chance to obtain volume discounts (economies of scale) • Full knowledge of number of technologies to be chosen for the entire province • Maximizing uniformity in technology installed across the province will help in technology rationalization in the future • Reduced risks to distributors • Provides central logistics planning for province to reduce inventory and establish optimal staging locations • Delivery compliance, product quality, contract disputes all dealt

Components of Procurement Strategy	OPTION 1: Distributor Procurement	OPTION 2: Centralized Provincial RFP to Multiple Vendors	OPTION 3: Centralized Provincial RFP to Prime Contractor
		(distributor allocation) • Could centralize sealing of meters	with by one entity increasing leverage of vendors • Equal importance attached to small and large distributor needs • Reduced reporting requirements from 90+ distributors • Allow for better control of distribution of supply to meet provincial implementation plan (distributor allocation) • Could centralize sealing of meters
Cons	• Reduced lot sizes may increase costs • Slower process to form groups • Province does not have as much direct control over outcome (number of technologies chosen, price paid, etc.)	• Larger lot sizes could result in large scale failure in statistical samples (must be managed over multiple distributors – or sealed by distributors) • Distributors may loss local pride of ownership of the procurement task which may lead to lower willingness to accept risk on innovative add-ons • Less chance of smaller innovative products from entering the market • Disburses responsibility between distributors and implementation coordinator	• Additional layer of costs • Complex contracting arrangement with many scope changes • Larger lot sizes could result in large scale failure in statistical samples (must be managed over multiple distributors – or sealed by distributors) • Distributors may loss local pride of ownership of the procurement task which may lead to lower willingness to accept risk on innovative add-ons • Less chance of smaller innovative products from entering the market • Disburses responsibility between distributors, prime contractor and implementation coordinator

Option 1 will be able to achieve low overall costs through the use of buying groups and other methods. It is unclear whether this amount of buyer consolidation will result in maximum economies of scale vs. a province wide procurement process. With multiple distributor groups purchasing, implementation risk is minimized, as a major issue encountered in one group will not necessarily affect all distributors. Since it leverages existing distributor buying processes and leaves full accountability on distributors, it will promote local distributor pride in the smart meter initiative. It is unclear whether a central process that provides one option for distributors to follow or a decentralize process that will likely use existing like minded distributor buying groups to purchase will result in the fastest, most efficient process in order to meet provincial timelines. One area of concern is the anticipated future technology rationalization in the province. If distributors with different smart meter technologies merge, it will result in higher systems consolidation costs. This issue can be address by the OEB monitoring the number of technologies being purchased through their procurement plan approval process. In addition, distributor buying groups will likely form by geography where regions of the province will choose similar technologies. Since any mergers that happen will likely happen among buying group members, technology rationalization will be facilitated by choosing a distributor buying group option. Option 1 will likely encourage the most innovation and economic development. Choosing enhanced functionality will be possible through business case submissions to the OEB.

Option 2 is similar to Option 1 since it would still involve a task force of distributors making technology decisions while being facilitated by the provincial implementation coordinator. The major difference between Option 1 and 2 is that Option 2 would not provide distributors full accountability for the process, would likely take less time to get the process going but because of the varying needs of distributors would be a complex and slower process to complete. With multiple vendors being contracted, implementation risk would be similar to Option 1. With respect to meeting government timelines, Option 2 would slow down early adopters among distributors who are anxious to get started on their deployment since they would have to wait for the provincial process. This option would provide the OEB with more control since the OEB would be facilitating the process that determines the final costs to be paid and the technologies chosen.

Option 3 would pass the coordination responsibilities of provincial deployment over to a prime contractor. The prime contractor would contract with individual vendors to provide distributors with technology alternatives. This option would be adding an additional layer of costs. With only one contracting entity, an issue with the prime contractor would put the entire provincial project at risk. Contracting with a prime contractor would likely be very complex and would take a long time to setup. It would ensure a discrete number of technologies implemented in the province that would minimize costs related to future customer transfers.

Both Option 2 and 3 would be adding an additional layer of costs and may or may not realize greater benefits from economies of scale.

Recommendations:

Option 1 is recommended. This option leverages existing distributor buying groups and allows for distributors to have flexibility in their buying choices to maximize the return on investment and through the OEB procurement plan approval process gives distributors some assurance of cost recovery and provides the OEB with some control over the ultimate decision (costs and technologies). It allows larger distributors that need to start deployment early to be able to go ahead with their contracting without having to wait for a slower provincial process.

Concerns about gaining economies of scale through buying groups and future costs related to customer transfers because of excessive technologies being chosen can be monitored through procurement process approvals.

Appendix B-5: Deployment Priorities and Individual Distributor Targets

Deployment Priorities

	BENEFITS								
CUSTOMER GROUP	**Reduce stranded costs**	**Improved customer choice**	**Early identification of technology issues**	**Reduce cross subsidization between customer groups**	**Early penetration in customer groups where government has ability to influence behaviour**	**Early reduction in manual reading**	**PRIORITY**	**NUMBER OF METERS**	**RECOMMENDATIONS AND RATIONALE**
New installations, service upgrades and meter changeouts	X						Work Program A and B - Priority 1	approx. 170,000 per year	This group was specifically chosen in the Minister's directive as a priority group. OEB should instruct distributors to include smart meters as a standard offering for new service connections in their Conditions of Service, much like has been done for interval meters on new services that have demands greater than 500 kW. Smart meters in this situation would be used as "dumb" meters until communication is setup in the area. The switch in meter types should not commence until communication technology is chosen for a given area and subject to availability of meter supply from vendors.
GS >50kW who request early installation		X					Work Program A - Priority 2	n/a	Since installations in this group would be on a one off basis, benefits of an organized deployment are not overly impacted. This would allow customers who are keen to change their consumption behaviour to be rewarded by having a smart meter installed quickly. Guidelines should be placed on distributors to install meters within 4-6 weeks of a request (except under extraordinary circumstances). There would be no additional cost for early installation requests except if the customer asks for an enhanced functionality meter or requested off-hours installation.
MUSH sector (publicly funded buildings)					X		Work Program A - Priority 3	n/a	This sector can be an example of leadership to the rest of the public to promote a conservation culture. Government may have more leverage on their behaviour in order to achieve reductions in peak demand.
General Service >50kW (non-interval metered)				X		X	Work Program A - Priority 4	approx. 50,000	This group was specifically chosen in the Minister's directive as a priority group. Presently this group has the "worst of all worlds". It is exposed to spot market prices through NSLS with no ability / reward to manage load. As well, since NSLS profile includes residential customers, this sector is likely subsidizing the peak usage of the residential sector. Installations for this sector are more complex and require certified meter technicians to install on a one off basis. There would be an early reduction in monthly / dispersed higher average cost reads. This sector represents 1-2% of all meters and around 60% of the provincial load.
Residential and GS <50kW (multi-phase)							Work Program A - Priority 5	n/a	This group would require certified meter technicians for installation.
General Service >50kW (interval metered which do not meet min requirements)							Work Program A - Priority 6	n/a	This group of customers already have interval meters but may not have the communications infrastructure to make them "smart" meters. The meters in this group will be allowed to be grandfathered.
Residential and GS <50kW (single phase)							Work Program B - Priority 1	approx. 4,300,000	The rate of deployment for the residential sector will be the fastest. Therefore it will be important to start this sector early to ensure that provincial targets are met. The installation resources used for this group will not be the same resources used for larger customers and therefore will not reduce deployment speed for larger customers. As well, studies done on US populations have found that this sector is most willing / capable to shift their consumption behaviour. Deployment for this sector should start in parallel with the deployment of meters to the >50kW sectors to ensure that 2007 targets are met.
Customers with existing pre-paid meters							–	approx. 2,000	This group of customers have non-interval meters with a pre-paid feature which has demonstrated significant reduction in demand. These meters will be allowed to be grandfathered, and will count towards meeting provincial targets.
Residential and GS <50kW who request early installation		X				X	–	--	Customers in this grouping will not be allowed to request early installations because it does nothing to assist in achieving efficiencies in installation both from a cost or timing perspective. Since regional communication infrastructure would need to be setup for meters to be operational, it is not cost effective to setup this infrastructure for a stand alone meter in an area.

Distributor Allocation Options Considered

	Benefits					
Distributor Allocation Options	Maximized benefits from priority group	Cost effective deployment	Early identification of technology issues	On-going work leveling	Recommendation and Rationale	Time Period
Early adopters to Pilot Technologies			X		Early adopters will be the most receptive and should be utilized to test technologies chosen for the province before other LDCs implement them. This will ensure early identification of technology issues and prevent issues arising after mass deployment starts. Pilot testing should be completed by Q4 of 2005. Failed technology is one of the greatest risks and current pilots should be strongly supported through upfront cost recovery approval.	Q1 to Q4 2005
Provincial sweep		X			Although a provincially optimized deployment strategy in theory would be the most cost effective, but in practice, with 90+ LDCs, different collective agreements to adhere to, future reverification work leveling issues and other LDC specific issues this approach is not recommended.	--
Start all LDC deployment at the same time				X	This deployment strategy is recommended since it will spread out future reverifications over the maximum number of years. The shorter the deployment period is relative to the expected in-service period for smart meters, the more spikes there will be in future reverification workload. It also allows for large customers in all utilities to request early installations.	Mid 2005 - 2010
Based on amount of priority customers in LDC's territory AND higher concentration of meters in congestion areas	X				LDCs will need to complete 100% of >50kW meters, new installations, meter changeouts, meter upgrades and 12% of the remaining <50kW meters in order to acheive the 2007 provincial target. The individual breakdown of where the meters get installed in each LDC territory will be driven by the amount of priority customer groups that exist in their territories. Those LDCs that have congestion areas in their territories (as defined by the IMO Outlook Report) will need to deploy all meters in Work Program B in congestion areas.	Completion of >50kW customers in 2005 - 2007 period; Higher penetration in congestion areas throughout 2005 - 2010 period
Allow LDCs that are choosing enhanced functionality to decide on their own priorities (based on technology chosen)	X		X		LDCs will be allowed to choose enhanced functionality (based on a business case). When enhanced functionality is chosen, the deployment strategy will be unique to the functionality that is being deployed and it will be left to the LDC to apply for approval by the implementation coordinator. LDC's may be able to provide strong business cases which demonstrate a much higher ROI if given this flexibility.	2005 - 2010

LDC Mass Deployment Suggestions

	BENEFITS						
Mass Deployment Suggestions for the the LDC	**Reduce stranded costs**	**Target highest needs of province**	**On-going work leveling**	**High speed of deployment**	**Cost effective deployment**	**Early reduction in manual reading**	**Recommendation and Rationale**
Congestion Areas (organized along meter reading routes)		X			X		The IMO has identified areas in the province that will have potential supply shortages due to coal plant closures or potential delivery contraints due to high growth areas. LDC with congested areas identified by the IMO should complete deployment of Workgroup B meters in congested areas first
Concentrate on areas (likely southern zones) where telecommunications are available, organize along meter reading routes			X	X	X		Provides for logistical economies, facilitates order quantity forcasting and possibly aligns with telecom rollout. It focuses on areas where immediate DSM opportunities are higher (air conditioning, pools). It focuses on installing lower cost customers and areas of higher growth first. A disadvantage is that it misses the higher cost to read customers (but this is a secondary driver)
Hard to access customers - within zones						X	These are still organized along meter reading routes (may want to combine seasonal and year-round routes) - telecommunications challenges / costs are higher in these areas - most seasonal / off-peak residences are in this group (lower consumption)
All remaining metered customers within zones, organize along meter reading routes							Remaining group

Meter Statistics and Estimates

	Customers				Priority Groups			
LDC Name	Res. Cust.	Commercial	Industrial	Total Cust.	GS > 200kW	GS 50kW - 200 kW	New Installs / Service Upgrades (per year)	Meter Changeouts (per year)
Hydro One Brampton	88,414	7,984	4	96,402		935	2,205	1,687
Hydro One Dx	1,041,526	100,858	364	1,142,748		**7,700**	**24,500**	**20,000**
Asphodel-Norwood Distribution	664	82	22	768		10	18	13
Atikokan Hydro Inc.	1,448	280	1	1,729		33	40	30
Aurora Hydro Connections Ltd.	12,792	1,374		14,166		161	324	248
Barrie Hydro Distribution Inc.	52,661	6,262		58,923		733	1,348	1,031
Bluewater Power Distribution Corp.	32,000	2,200	304	34,504		258	789	604
Brant County Power Inc.	6,883	450	1,000	8,333		53	191	146
Brantford Power Inc.	30,903	2,948	387	34,238		345	783	599
Burlington Hydro Inc.	47,000	5,000		52,000		585	1,189	910
Cambridge & North Dumfries Hydro Inc.	39,400	4,223	650	44,273		494	1,013	775
Canadian Niagara Power Inc. (Fort Erie/Port colborne)	21,450	2,595		24,045		304	550	421
Centre Wellington Hydro Ltd.	4,961	665	7	5,633		78	129	99
Chapleau Public Utilities Corp.	1,174	196		1,370		23	31	24
Chatham Kent Hydro Inc.	28,285	3,793	3	32,081		444	734	561
Clinton Power Inc.	1,369	249		1,618		29	37	28
Collus Power Corp.	11,300	1,530	90	12,920		**60**	295	226
Cooperative Hydro Embrun Inc.	1,325	187		1,512		22	35	26
Cornwall Electric	22,600			22,600		0	517	396
Dutton Hydro Ltd.	470	96		566		11	13	10
Eastern Ontario Power Inc. (Granite)	3,011	466	6	3,483		55	80	61
ELK Energy	9,085	1,099	1	10,185		129	233	178
Enersource Hydro Mississauga	149,470	19,820		169,290		2,320	3,872	2,963
ENWIN Powerlines Ltd.	71,921	8,168	11	80,100		956	1,832	1,402
Erie Thames Powerlines Corp.	11,800	1,402	102	13,304		164	304	233
Espanola Regional Hydro Dist. Corp.	2,949	404		3,353		47	77	59
Essex Powerlines Corp.	24,396	1,500	586	26,482		176	606	463
Festival Hydro	15,932	2,081		18,013		244	412	315
Fort Francis Power Corp.	3,292	499		3,791		58	87	66
Grand Valley Energy				678		0	16	12
Gravenhurst Hydro Electric Inc.	5,049	716		5,765		84	132	101
Great Lakes Power Ltd. - Distribution	10,378	992	2	11,372		116	260	199
Greater Sudbury Hydro Inc.	38,670	4,694		43,364		549	992	759
Grimsby Power Inc.	7,850	696	105	8,651		81	198	151
Guelph Hydro Electric System Inc.	36,837	3,714		40,551		435	927	710
Haldimand County Hydro Inc.	17,398	2,535		19,933		297	456	349
Halton Hills Hydro Inc.	16,132	1,605	22	17,759		188	406	311
Hamilton Hydro Inc.	175,000			175,000		**1,513**	4,002	3,063
Hearst Power Dist. Co. Ltd.	2,319	429	3	2,751		50	63	48

Meter Statistics and Estimates – Cont'd

	Customers				Priority Groups			
LDC Name	Res. Cust.	Commercial	Industrial	Total Cust.	GS > 200kW	GS 50kW - 200 kW	New Installs / Service Upgrades (per year)	Meter Changeouts (per year)
Hydro 2000 Inc.	954	164		1,118		19	26	20
Hydro Hawkesbury Inc.	4,529	551	75	5,155		65	118	90
Hydro Ottawa Ltd.	237,019	26,761		263,780		3,133	6,033	4,617
Innisfil Hydro Dist. Systems Ltd.	12,100	843	68	13,011		99	298	228
Kenora Hydro	4,984	822		5,806		96	133	102
Kingston Electricity Distribution Ltd.	22,607	3,446	425	26,478		403	606	463
Kitchener-Wilmot Hydro Inc.	65,552	7,632	4	73,188		893	1,674	1,281
Lakefield Distribution	1,148	199	14	1,361		23	31	24
Lakefront Utilities Inc.	7,271	1,132	12	8,415		133	192	147
Lakeland Power Dist. Ltd.	7,147	1,631		8,778		191	201	154
London Hydro Inc.	119,000	11,600	1,400	132,000		1,358	3,019	2,310
Middlesex Power	5,823	781	1	6,605		91	151	116
Midland Power Utility Corp.	6,000	300	30	6,330		35	145	111
Milton Hydro Dist. Inc.	12,284	2,045	12	14,341		**230**	**1,964**	251
Newbury Hydro	159	29		188		3	4	3
Newmarket Hydro Ltd.	20,700	2,600	275	23,575		304	539	413
Niagara Falls Hydro Inc.	29,124	3,590		32,714		420	748	573
Niagara-on-the Lake Hydro Inc.	5,488	1,257	100	6,845		147	157	120
Norfolk Power	15,250	2,160	150	17,560		253	402	307
North Bay Hydro Dist. Ltd.	20,193	3,075	0	23,268		360	532	407
Northern Ontario Wires	5,467	903		6,370		106	146	111
Oakville	45,563	5,633		51,196		659	1,171	896
Orangeville Hydro Ltd.	8,404	843	132	9,379		99	215	164
Orillia Power Dist. Corp.	10,512	1,597		12,109		187	277	212
Oshawa PUC Networks Inc.	42,702	4,171	41	46,914		488	1,073	821
Ottawa River Power Corp.	8,304	4,271		12,575		500	288	220
Parry Sound Power Corp.	2,573	608	nil	3,181		71	73	56
Peninsula West Utilities LTd.	13,750	250		14,000		29	320	245
Peterborough Distribution	26,965	3,290	963	31,218		385	714	546
PUC Distribution Inc.	28,500	3,800		32,300		445	739	565
Renfrew Hydro Inc.	3,430	591		4,021		69	92	70
Rideau St Lawrence Dist. Inc.	4,857	773	63	5,693		90	130	100
Scugog Hydro Energy Corp.	1,850	450		2,300		53	53	40

Meter Statistics and Estimates – Cont'd

	Customers				Priority Groups			
LDC Name	**Res. Cust.**	**Commercial**	**Industrial**	**Total Cust.**	**GS > 200kW**	**GS 50kW - 200 kW**	**New Installs / Service Upgrades (per year)**	**Meter Changeouts (per year)**
Sioux Lookout Hydro Inc.	2,267	459	1	2,727		54	62	48
St. Catharines Hydro Utility Services Inc.	45,995	5,166	4	51,165		605	1,170	895
St. Thomas Energy Inc.	12,700	1,600		14,300		187	327	250
Tay Hydro Electric Dist. Co.	3,604	296		3,900		35	89	68
Terrace Bay Superior Wires Inc.	836	110		946		13	22	17
Thunder Bay Hydro Elec. Dist.	43,900	5,223	3	49,126		611	1,124	860
Tillsonburg Hydro Inc.	5,400	800		6,200		94	142	109
Toronto Hydro Elec. System Ltd.	585,527	78,076		663,603		**11,862**	15,177	11,614
Power Stream	156,710	21,226	2,171	180,107		2,485	4,119	3,152
Veridian Corp.	80,992	8,166	3	89,161		956	2,039	1,560
Wasaga Distribution Inc.	8,530	841	0	9,371		98	214	164
Waterloo North Hydro Inc.	38,814	4,967	631	44,412		581	1,016	777
Welland Hydro Electric System Corp.	19,140	2,105	10	21,255		246	486	372
Wellington Electric Distribution Co.	1,089	126		1,215		15	28	21
Wellington North Power Inc.	2,764	467	44	3,275		55	75	57
West Coast Huron Energy Inc.	3,157	496	41	3,694		58	84	65
West Nipissing Energy Services Ltd.	2,875	290		3,165		34	72	55
West Perth Power Inc.	1,425	235	20	1,680		28	38	29
Westario Power Inc.	17,557	2,391	260	20,208		280	462	354
Whitby Hydro Elec. Corp.	27,500	2,500		30,000		293	686	525
Woodstock Hydro Services Inc.	12,423	1,453		13,876		170	317	243
TOTAL	**3,921,528**	**426,583**	**10,623**	**4,359,412**		**49,937**	**99,705**	**76,297**

Composite								
Composite Group (Actual data)		182,509		1,157,089		21,365	26,464	20,000
Composite (%)						11.7%	2.3%	1.8%

NOTES:

1. Source of data from 2002 OEB regulatory filings
2. Breakdown of priority groups based on composite percentages from Hydro One, Toronto Hydro, Hamilton Hydro, Milton Hydro and Collus Hydro (shown with yellow highlights)

Appendix B-6: Potential Barriers and Mitigations Plans

Potential Barrier	Background	Type of Risk	Level of Risk	Mitigation Plan to Reduce Risk
Delayed Decision Making by External Agencies	▪ Delayed decisions by agencies may jeopardize timelines ▪ Decisions that alter requirements may affect contracts	Implementation Financial	Probability M Impact H	▪ Effective governance and issue management through steering committee setup early on ▪ Identify changes necessary in OEB instruments (codes and licenses) ▪ Clearly communicate required decisions dates and impact of missing dates ▪ Vendors to work with MC to facilitate approvals ▪ Work with CSA for approvals and recognition of UL certification ▪ Establish flexible contracts that anticipate problems
Insufficient Supplier Availability ▪ IT ▪ Meters ▪ Communications	▪ Could be affected by delayed decision making of regulatory agencies ▪ Affected by number of vendors chosen ▪ Minimum requirements could eliminate available vendors to choose from ▪ Products may be available in the U.S., but do not have CSA or MC approvals ▪ Supplier availability may be affected by size of order	Implementation Financial	Probability L Impact H	▪ Setup overall schedule to be aware of lead times required ▪ Ensure technical and commercial requirements are not too stringent to avoid too few suppliers ▪ Seek to amalgamate purchase requirements

Potential Barrier	Background	Type of Risk	Level of Risk	Mitigation Plan to Reduce Risk
Contract Defaults by Suppliers	▪ Suppliers may not be able to meet supply requirements ▪ Supplier may not be capable of meeting required timeframes ▪ The supplier may go bankrupt	Implementation Financial Operational	Probability M Impact L	▪ Proper contracts, and careful review of actual abilities vs. stated abilities prior to engaging suppliers ▪ Avoid sole supplier arrangements ▪ Conduct vendor research ▪ Supervise suppliers, enforce contract milestones ▪ Perform credit assessment and ensure financial viability of suppliers before contracting with them
Poor Product and Installation Quality	▪ Sudden increase in manufacturing of product in tight timelines increases the risk of reduced quality control ▪ Quality issues are often not apparent until some time after meter installation or warranty expiration ▪ New vendors may introduce products without securing necessary federal approvals ▪ Vendors will not pay any post-warranty costs associated with product recalls ▪ Most meter test shops will not be able to calibrate or service electronic meters in-house	Financial Operational	Probability L Impact H	▪ Setup alternate suppliers to deal with quality issues ▪ Setup sample test installations early and obtain assurance of cost recovery from OEB ▪ Test all chosen technologies early in the process to identify any issues as early as possible ▪ Ensure accredited meter verifiers provide meter sealing services ▪ Ensure proper training and skill levels of contract hires, and establish accountabilities for error and dispute resolution ▪ Ensure contracting terms specify expectations of quality and push risk onto vendors through penalty clauses ▪ Ensure meters have capability of remote software patches

Potential Barrier	Background	Type of Risk	Level of Risk	Mitigation Plan to Reduce Risk
Resource issues ▪ collective bargaining agreements ▪ insufficient installation resources	▪ Collective bargaining agreements (CBA) may preclude some contracting out arrangements for distributors ▪ Distributor or service provider may not have adequate resources for implementation plan ▪ CBA may prevent distributor from utilizing external resources ▪ Currently there are a number of strikes underway with contracting out as prime issues ▪ Distributors may be required to use high priced resources for low skill work ▪ Lack of skilled labour from service providers ▪ Training of available installers may not be an issue for residential single phase metering, but could be an issue if fast deployment of complex metering is expected	Implementation Financial Operational	Probability M Impact H	▪ Distributors should create open dialogue with bargaining units and respect agreements ▪ Review and understand options/agreements regarding temporary and contract labour ▪ Ensure that implementation plan does not make false assumptions about the availability of outside resources ▪ Ensuring use of existing staff for complex metering may mitigate concerns over loss of jobs ▪ Train resources using available training programs and facilities where appropriate ▪ Hire resources from external service providers ▪ Develop inter-utility resource sharing arrangements where possible ▪ Allow for adequately staged implementation ▪ Allow for recovery of increased costs if new staff hiring and training is required ▪ Work with collective bargaining units and their hiring halls to obtain resources if cost effective

Appendix B-7: Preliminary Analysis of Distributor Impacts

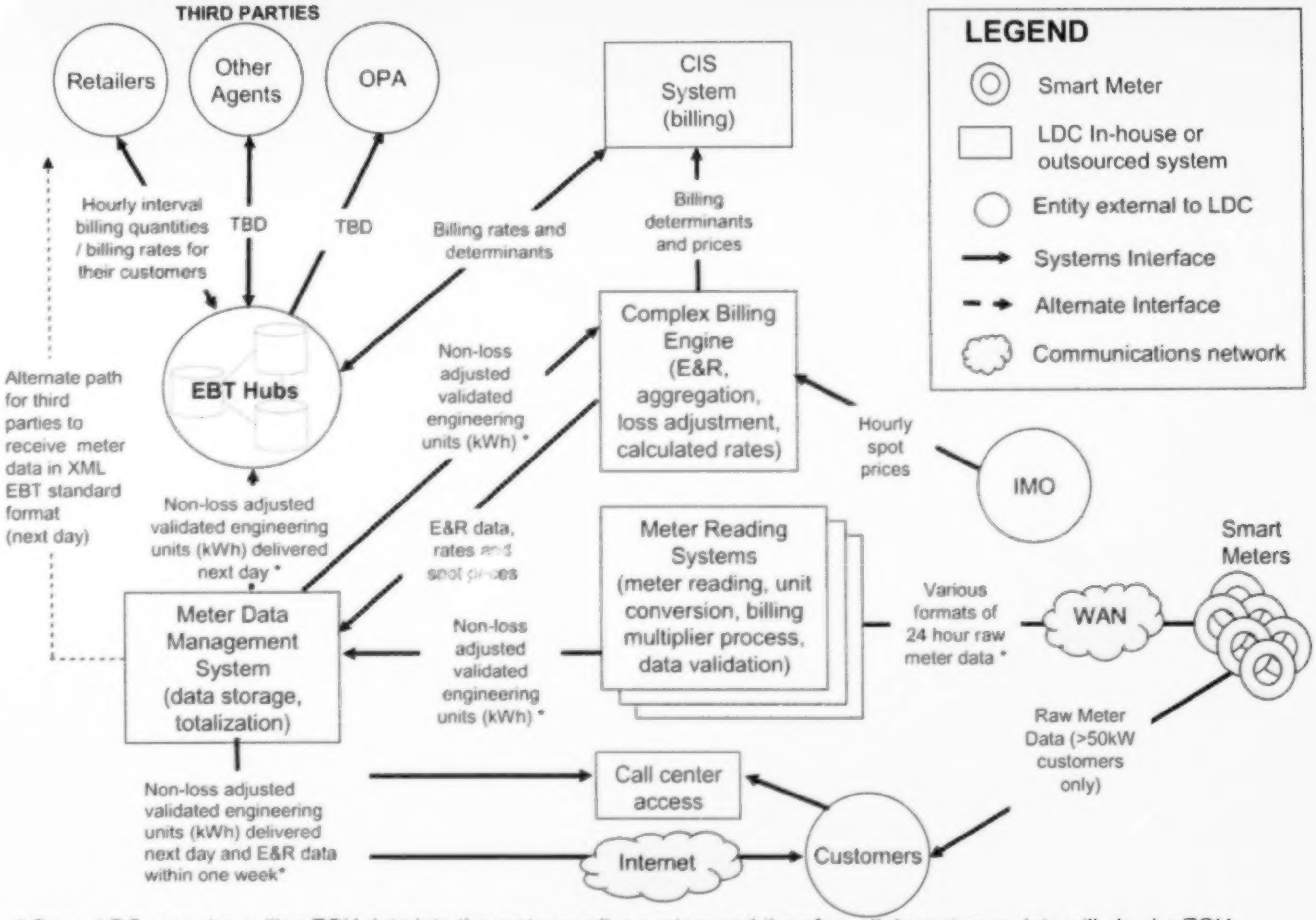
Preliminary Distributor Business Process, Systems and Staffing Impacts

LDC Impacted Area	Business Process Impacts	Systems / Equipment Impacts	Staffing Impacts
Meter Reading	▪ Elimination of manual cycle meter readings (exceptions excluded) ▪ New meter reading processes	▪ New meter reading systems ▪ Integration with meter data management system ▪ Legacy systems retired ▪ Changes to meter reading cycles in CIS	▪ Redeployment and retraining of all meter readers ▪ Possible increase in IT support staff
Meter Data Management	▪ New data handling processes (triggers to update data tables) ▪ New E&R processes ▪ Timing changes in data provision ▪ Data access rights ▪ Archive / backup processes	▪ Integration with meter reading system ▪ Integration with EBT hubs (or alternate interface) ▪ Integration with complex billing module ▪ Interface with OPA ▪ Increased storage and processing capacity	▪ Increase in IT support staff
Meter Data Provision to Customer	▪ Data posting process ▪ Customer security / access	▪ Internet web server capacity ▪ Internet security ▪ Tool development for customer data viewing	▪ Increase in IT support staff

LDC Impacted Area	Business Process Impacts	Systems / Equipment Impacts	Staffing Impacts
Billing and Back Office	▪ Possible change in billing cycles and their timing and frequency ▪ Change in EBT processes ▪ Changes to settlements with retailers and customers	▪ Change in rate structure ▪ New interfaces with meter data management system ▪ New interfaces with complex billing engines	▪ Training of staff on changes to billing system
Customer Service / Call Center	▪ Lower call volumes related to estimated bills and more available usage data ▪ Increase in call volumes related to internet usage ▪ Increase in call volumes if bills become more complex ▪ Increased call volumes due to customers calling in to obtain usage information ▪ Possible reduction in outage related calls ▪ New scripts for call center agents	▪ Access to systems to address inquiries / disputes (i.e. customer bills, security access, interval data)	▪ Retraining of call center staff on new scripts ▪ Potential FTE impact (increase in calls in some issues, decrease in others)
Contract Management	▪ New contracting arrangements with external service providers ▪ Buy out of existing contracts	▪ None	▪ None
Provincial Reporting	▪ New reporting requirements to implementation coordinator on progress and costs ▪	▪ System functionality developed to meet reporting requirements	▪ Staffing impact depends on reporting requirement (not yet specified)

LDC Impacted Area	Business Process Impacts	Systems / Equipment Impacts	Staffing Impacts
Meter Shop	▪ During transition period, sample testing continues but individual meter reverification ceases since those meters are replaced with new smart meters ▪ New accreditations due to new meter standard ▪ Sampling continues (assumption that Measurement Canada will allow). ▪ Additional sealing activity will result during transition period if vendors do not have accredited meter shops ▪ Initial verification of single phase smart meters will increase due to required 100% testing (acceptance sampling not allowed for electronic meters in the current rules)	▪ New vendor specific verification equipment for smart meters	▪ Possible increase in staff if sealing required during transition period ▪ Possible reduction in workload due to elimination in reverification ▪ Possible increase in workload due to higher statistical sampling requirements and shorter reseal periods ▪ Training required on new product lines
Meter Communication Infrastructure	▪ Processes to respond to outages on the meter communications infrastructure ▪ Contracting arrangements with third party providers (including performance monitoring)	▪ Network management software ▪ Communications infrastructure equipment	▪ If technology is purchased new staff or new outsourcing arrangements will need to be put in place

Illustrative Distributor Smart Metering Architecture for Data Management and Settlements


THIRD PARTIES
Retailers
Other Agents
OPA
CIS System (billing)
LEGEND
Smart Meter
LDC In-house or outsourced system
Entity external to LDC
Systems Interface
Alternate Interface
Communications network
Hourly interval billing quantities / billing rates for their customers
TBD
TBD
Billing rates and determinants
Billing determinants and prices
EBT Hubs
Complex Billing Engine (E&R, aggregation, loss adjustment, calculated rates)
Non-loss adjusted validated engineering units (kWh) *
Alternate path for third parties to receive meter data in XML EBT standard format (next day)
Hourly spot prices
IMO
Non-loss adjusted validated engineering units (kWh) delivered next day *
E&R data, rates and spot prices
Meter Reading Systems (meter reading, unit conversion, billing multiplier process, data validation)
Smart Meters
Meter Data Management System (data storage, totalization)
Non-loss adjusted validated engineering units (kWh) *
Various formats of 24 hour raw meter data *
WAN
Raw Meter Data (>50kW customers only)
Call center access
Non-loss adjusted validated engineering units (kWh) delivered next day and E&R data within one week*
Internet
Customers

* Some LDCs may be pulling TOU data into the meter reading system and therefore all downstream data will also be TOU

Appendix C. Costs

Appendix C-1: Smart Metering Benefits

Table 1

	Category	Source of Benefit	Value	Operating Savings $/month	Offsetting Costs
1.	Broader social benefits	Improved efficiency of generation, transmission and distribution environmental and health benefits associated with lower greenhouse and acid gas. Emissions from generators avoided costs for new Generation improved ability to meet international agreement targets e.g. Kyoto			
2.	Customer benefits	Information to control usage lower electricity costs New service innovations facilitated by smart metering infrastructure			
3.	Innovation in services	TOU data will permit creation of new retailer services and assist LDC to optimize its services			Unknown but likely involves some capital investment to realize benefit
4.	Elimination of estimated reads	Improved cash flow from actual read bills, fewer high bill complaints	Estimated $.03/meter/month See Char Nnotes	$0.03	More complex rate plans may offset any benefit
5.	DSM initiatives	TOU data supports focused DSM efforts and feedback to confirm program effectiveness			May require new analysis software
6.	Increased meter accuracy	Electromechanical meters subject to accuracy drift as they age	No savings because compensated for in loss uplift (see Chart Notes)		
7.	Manual meter reading costs	AMR will displace manual reads	Savings est. $0.30 /meter/month See Chart Notes	$0.30	AMR reading costs est. $0.10-$0.50 per meter/month - remaining manual reads may increase as vol. declines
8.	Remote final and check reads	AMR will displace manual reads	Savings $0.06 - $0.33 /meter/month See Chart Notes	$0.06	None if not caused by meter malfunction requiring site visit
9.	Cash flow improvement	More frequent billing by LDCs	Questionable value See Chart Notes		Cost of preparing and sending more frequent bills may exceed cashflow benefits

	Category	Source of Benefit	Value	Operating Savings $/month	Offsetting Costs
10.	Theft of power detection	Changeover will reveal tampering New meters can detect tampering	Cleanup of system may return large value - ongoing detection minimal See Chartnotes		Does not apply if meter bypassed
11.	Remote disconnect/reconnect	Elimination of need for site visit	Est. $25/visit See Chartnotes		Requires standard feature of switch in meter and bi directional comm
12.	Remote outage sensing	More efficient outage management eliminates repeat crew visits for missed customers	Est. $200/crew revisit See Chartnotes		May require integration of meter data with other systems to realize benefit
13.	Distribution system optimization and System Planning	Customer data allows more accurate design, reduced system losses, better timing of capital investments	Minimal value - LDCs already have tools to optimize See Chartnotes		May require new analysis software and integration of metering data
14.	Detection of equipment overload	Reduced equipment damage	Unknown		None

Chart Notes for Table 1 – Benefits of Smart Metering

Some benefits as numbered in the above table are further explained here.

Benefit #4 – Elimination of Estimated Reads

Many utilities estimate consumption on residential accounts to avoid meter reading costs. Estimates are based on the customer's consumption history and true ups are done from actual reads at least annually and usually more often. Automatic meter reading will produce accurate bill data and eliminate estimated reads. The value to an LDC arises from two sources:

1. It is assumed that estimated bills are understated and that the LDC incurs a carrying cost equal to the amount of the underpayment times its weighted average cost of capital. This carrying cost applies until the account is trued up. There are several problems with this analysis. One is the assumption that the estimate always understates actual consumption. In fact, it may be equally likely that the estimate overstates actual consumption and the LDC is deriving a prepayment benefit from estimated bills. The second problem is the assumption that an LDC that chronically underestimates never takes any action to correct the problem. LDC members of the cost considerations study group found this scenario unlikely. In fact, estimation accuracy is monitored and corrected so that chronic over or under estimation does not occur.

2. The second source of cost savings arises from the idea that customers who receive inaccurate bills will complain and drive up an LDC's customer service costs. The assumption underlying this idea is that the customer is being overbilled because underbilled customers derive a benefit and probably don't complain about it. However, this assumption conflicts with the hypothesis in note 1 above that estimated reads are low not high – they can't be both at the same time.

The conclusion of the study group is that estimated bills are as likely to be overestimated as underestimated so the carrying cost associated with lower than actual bills is probably offset by the prepayment benefit associated with higher than actual bills. The group also concluded that estimation algorithms based on previous customer consumption history are sophisticated enough that errors sufficient to attract a customer's notice and generate a complaint are fairly rare. If those complaints involve 1% of customers and take 10 minutes of customer service time to resolve then the avoided cost would be in the order of $.03/meter/month. (10 min. x $20/hour marginal cost for CS staff divided by 100)

Others do not agree with this conclusion and prefer the CERA[8] analysis that proposes call center reductions, (some of which would be attributable to decreased estimated bill complaints), in the range of $0.10 and $0.24 USD /meter/month. The cost group's opinion is that more complex rate plans, daily billing data and the publicity that will attend critical peak pricing calls will likely lead to increased customer calls and, therefore, higher not lower overall call center costs, at least for the foreseeable future.

Benefit #6 – Increased Meter Accuracy

Electromechanical meters are prone to accuracy drift as they age due to wear on moving parts. The meter typically slows down which results in more energy being consumed than is registered and billed. Electronic meters, by contrast, have no moving parts and do not suffer from accuracy drift. Conversion to electronic meters then should produce a benefit for LDCs in recovering at the retail level a greater proportion of the cost of power purchased at the wholesale level. Currently the difference between the two falls into the system losses category and is recovered as an uplift to consumption. Typical utility uplifts for losses are in the 3% to 5% range and include everything from metering errors to line and equipment losses and theft. The uplift rate is approved by the regulator and currently reflects loss experience from the base years of 1995 to 1999. If losses have changed since then the LDC may not be fully recovering the difference between wholesale purchases and retail sales. However, most elements of the loss uplift, with the possible exception of theft which is discussed in a later chartnote, are relatively static and at least the meter accuracy component is probably the same as it was in the base year. This conclusion is based on the fact that new meters are continually added to the population as the LDC experiences growth and as meters are reverified. This tends to offset the average accuracy drift as the population ages.

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[8] Cambridge Energy Research Associates conducted a study compiling cost benefit analyses from 12 US utilities assessing automated meter reading systems. Figures quoted here are from the *Utility Remote Metering Benefits* part of that study which was provided to the group by a participant in another study group.

Because of the uplift charge, LDCs are not actually losing any money because of slow meters, but just recovering it in the consumption uplift factor rather than in the actual consumption read on the meter. The same argument applies to customers who, as a group, do not pay for any more than they consumed. It might be argued that better meter accuracy distributes the consumption charge more fairly by not penalizing customers with an uplift charge if their meter reads accurately. This is true but meter inaccuracy is just one element of the uplift pool. Allocation of system losses is not done on a customer level even though where on the system a customer resides influences the line and equipment losses incurred to serve him/her. For example, customers close in to a distribution or transformer station cause less line loss than customers far out on the system. There is no recognition of this disparity in the uplift charge either.

Because of the uplift recovery of meter inaccuracies, the cost group does not attribute a cost savings to increased meter accuracy.

Others disagree and prefer the CERA analysis that sets this benefit at between $.01 and $.50 /meter/month. It is possible that the utilities comprising that study do not have an uplift factor to recover losses and, in that case, the savings would be legitimate.

Benefit #7 – Manual Meter Reading Costs

Automatic meter reading replaces the need for manual reading and therefore saves in labour and equipment devoted to that purpose. The cost study group estimates those savings to be between $0.30 and $1.50 per read, the variability arising from customer density and whether meter reading is conducted by contract or with in house staff. The higher cost applies to those utilities with less dense customer bases and who do the reading with there own staff. Most urban and suburban utilities in Ontario contract meter reading to private firms that are able to realize large economies of scale and who pay their meter readers substantially less than comparable utility staff. The result is very competitive rates per meter read. When this is combined with the tendency for utilities to minimize the number of times they actually read the meter in a year, the cost per meter per year can be very low. Many LDCs read bimonthly or quarterly so that total cost per customer per year can be under $2.00 resulting in a monthly cost per customer in the range of $0.20. Of course, as read frequency increases so does the monthly cost in a manual system. The cost group concluded that, on average, manual meter reads might cost about $.30 per customer per month which would be saved by automatic meter reading. This is partially offset by the cost of operating an automatic meter reading system which is considered elsewhere in this report.

Some will not agree with the position taken by the cost group and will prefer other analyses. CERA, for example, suggests that reduced meter reading costs will range from $0.61 - $0.85 USD per meter per month. These savings are higher than the actual cost of reading meters for many LDCs in Ontario and may result from in house rather than contract staff being used or be applicable to Utilities with much lower customer density. Whatever the reason, the cost group decided that the data could not be applicable in Ontario.

Benefit #8 – Final and Check Reads

Move in and move out reads are done in a variety of ways at LDCs. In many, LDC staff conduct custom meter reads to prepare final bills for customers moving out and to establish the initial reading for the customer moving in. The cost of these reads varies widely but, for suburban utilities using LDC staff, the group estimated it at $25.

Other LDCs advise customers that final reads are conducted as part of a route on particular days that might not coincide with the actual move out day. This is usually acceptable to the customer because the billing difference is small. The cost of doing final reads this way can be as low as $1.50 per read when conducted by meter reading contractors on a route basis.

Check reads are done to respond to customer high bill complaints. These often involve utility staff to investigate and are estimated to cost $25 per visit.

Both final and check reads can be done by AMR systems on demand and so the cost savings can be substantial particularly in utilities with a highly mobile customer base. College and University towns are a good example where students move in September and May causing many final reads for utilities. These, though, are usually concentrated around the institution and at specific times of the year so that economies of scale apply and the cost per read is much lower than the $25 referenced above. For these situations, the cost group estimated the read cost at $2.00 to recognize that many reads in the same area on the same day provide some economies of scale. Because of the variability of LDC customer bases that drive final read costs, it is hard to draw average per customer savings conclusions. In the university town example, 20% of the customer base might move in a year but using $2.00 per read and spreading the cost back over the entire customer base results in a savings attributable to AMR reading of $0.07 /meter/month. ($2.00 *.2 * 2 reads/12 months).

For other less mobile customer bases, 3% mobility might be more applicable but the higher cost of $25 per final ready might apply. In this case the cost averaged over the entire customer base would be $0.06 /meter/month ($25 * .03/12).

Because this second mobility might also apply generally to the university town situation the total savings per customer per year in that situation would be the sum of the two or $0.13 /meter/month. Thus the range of savings for check and final reads is taken to be $0.06 to $0.13. The actual cost of the AMR reads has not been subtracted from the savings because it would be nominal when spread over the entire customer base.

Benefit #9 – Cash Flow Improvement

Many utilities bill residential customers bimonthly or quarterly and some believe that monthly billing would improve cash flow for the LDC and result in financing savings. Automatic meter reading would support more frequent billing because the billing data would be available which would not be the case in a manual system where the meter is read less frequently. The financing savings arise from the fact that customers who are billed only bimonthly are carried by the LDC because electricity billing is in arrears not in advance. For a customer bill of $100 per month at a weighted average cost of capital of 8.3% this financing cost is $0.70 per month ($100 * .083/12). For bimonthly billed customers that are switched to monthly billing, there would be six of these occurrences that could be saved per year resulting in an average savings per month of $0.35. However, these savings are offset by the cost of preparing and delivering the extra six bills per year and of processing the payment received. Bill preparation, mailing and processing cost is estimated at $1.00 per event so that the average cost increase for six more bills per year would be $0.50 per month which is higher than the cost of financing customers on bimonthly billing.

For this reason, the cost group concluded that there were no net cash flow savings available from more frequent billing.

Benefit #10 – Theft of Power Detection

Theft of power by tampering with the meter is detectable by most electronic meters and reportable over an AMR system. Electromechanical meter tampering, by contrast, requires a manual inspection to detect, one usually performed by meter readers presently. To the extent that smart meters detect more of these instances of tampering than meter readers do, there could be a benefit.

In Ontario, the more common mode of theft is by meter bypass and that is not detectable by smart meter systems. Bypass consists of attaching unauthorized conductors to the secondary supply wires on the line side of the meter. Power is then diverted before it enters the meter. Doing this on overhead systems is relatively easy but it is also fairly easy to spot because hiding the illegal conductors is a problem. Attaching to underground conductors requires more effort and skill but when properly done it is almost impossible to detect without gaining access to the inside of the house. Presently, meter readers make visual inspections of meters and overhead systems as they visit each location. Many illegal bypasses of overhead systems and tampering with the meter are detected by this method.

Some hidden connections such as those inside the meter base are not easily detected by visual inspection but will be detectable by smart meters because the meter has to be removed to get at the base and this disturbance of the meter triggers a tampering message that is read by the AMR. Old connections that are cleverly concealed may be revealed during smart meter conversion as the old meter is removed and the base exposed. The project is expected to yield some benefits then as longstanding bypasses are eliminated. Initial installation of smart meters is expected to yield benefits because many of these invisible connections will be revealed when the old meter is removed. On the other hand, once it becomes generally known that meter readers are no longer making visual inspections, the incidence of bypass might increase and this is not detectable by smart meters as long as the meter is not disturbed.

In terms of benefit to the LDC, elimination of theft will increase revenues but the utility was not necessarily losing that revenue before smart meters. This is because LDCs are permitted an uplift on consumption to recover system losses of which theft forms a part. The amount of uplift is based on 1995 to 1999 losses so theft instituted prior to that time is already included in the recovery. As rebasing occurs, system losses are updated and the uplift charge adjusted accordingly. Ultimately the benefits of reducing theft flow to the customer by way of lower rates.

Bypass theft has increased since 1999 with the proliferation of grow houses. These losses are not being totally recovered in the uplift because they did not exist in the base year data. Therefore, LDCs are under collecting energy charges from customers and financing the cost of uncollected losses. To the extent that the bypass is discoverable during smart meter deployment, LDCs will realize some benefit in more complete recovery of power costs. However, many grow operators deliberately choose underground residential systems in which to locate simply because detection of the illegal bypass is much more difficult than with overhead systems.

Beyond the initial detection benefit from smart meter conversion already mentioned, ongoing savings from theft of power detection are not expected because smart meters are no more able to detect bypass than the existing electromechanical ones. The fact that some overhead bypass is discovered by meter readers now and that this benefit will be lost with the introduction of smart metering, led the cost study group to conclude that cost savings would not materialize in this category.

Other studies put the value of theft detection much higher. The CERA study, for example, suggests a range of from $0.10 to $1.33 USD per meter per month. The high part of this range would translate into about $1.66 per month in Canadian dollars using an exchange rate of 0.80. For an average suburban customer consuming about $50 in commodity a month, this amount of theft would exceed the entire uplift charge for all LDC system losses[9] not just theft. The cost group decided that it must be based on a theft experience unknown in Ontario and therefore excluded it as inapplicable. The lower part of the range might be reasonable if meter tampering is the predominant method of theft. However, even if that is the case, amateur attempts at tampering are often detectable by meter readers now and professionals will prefer bypass because it is undectable by any meter. Accordingly, even the low end figure appears to be too high to the cost group.

The final consideration is whether or not higher resolution of meter data might assist an LDC in detecting theft. Presently, billing systems can be programmed to spot suspicious changes in consumption patterns that might indicate that an illegal bypass has just been made. A field check of demand is then made by comparing clip on ammeter readings at the supply transformer end of the secondary conductors with the indication on the meter. Some advantage will accrue to having remote readings for the meter end in this case particularly if approaching the customer's residence might be dangerous. The field investigation would still be necessary to confirm bypass though.

The group heard suggestions that comparing consumption patterns between customers in the same neighbourhood might reveal theft. This idea has some potential in the case of grow operations which are usually sophisticated enough to simulate normal consumption by connecting some load through the meter. Right now detection of an unusual daily pattern of that metered consumption is not possible because only monthly consumption data is available. Smart meters will allow construction of daily consumption patterns and it is not unlikely that grow operations will exhibit some identifying characteristics. Detailed studies will be needed to validate the technique before it can be used, though, and the cost group was hesitant about ascribing benefits to a strategy that might be defeated by installing timers on loads to simulate a normal consumption pattern.

It is possible to detect theft if the supply transformer has its own meter which can then be compared to the totalized readings of customer meters supplied by it and in that case remote reading capability is a definite advantage. However, there are technical and cost hurdles to be overcome with this idea and any utility considering it would probably be better off just installing all customer meters at the transformer secondaries and eliminate the possibility of bypass altogether.

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[9] Assuming an average uplift of 3% for losses most of which is attributable to line and equipment losses not theft.

Overall, the cost group doubts that any real benefit will accrue from smart metering in the area of theft detection and so has attached no value to it.

Benefit #12 – Improved Outage Management

Smart meter data and communication capability are the basis for improved outage management claims. To analyze the benefits, outages need to be broken down into their constituent stages. The cost group chose three stages for this purpose:

Notification of LDC operators that a customer is out of power is the smallest time consuming part of the event and usually occurs through the utility's SCADA system that reports equipment status or through a telephone call from the customer. In either case, operators are usually aware of an outage very quickly after its initiation. Notification through an AMR system through normal meter reading activity could not be relied on because the read would probably not coincide with the outage. If smart meters have no voltage sensing features that initiate a call to the AMR then this could be relied upon for notification but, otherwise, routine meter read polling would probably not coincide with an outage so would be of no value in notification. In either event, any economies realized through faster or more comprehensive notification by smart meters would not be a significant benefit because this phase of the outage is such a small part of the overall outage time.

Dispatch and Repair is the part of the outage that consumes the most time. If the outage is very widespread due to a lot of equipment damage that might occur in severe storms then the dispatch of crews and efficient management of repairs can be a complex task. No voltage information from meters could be useful in these cases if integrated into automated mapping systems so that an operator had a graphical display of the parts of the system that are out of service. However, widespread outages of this kind are rare in most utilities. The predominant outage is usually related to vehicles hitting poles or transformers or an equipment fault caused by isolated lightning strikes or tree branches making contact with overhead conductors. These outages do not generally require more than one or two line crews to effect repairs and do not pose complex labour and equipment management issues that would benefit from smart meter data. For most outages, meter data information would probably not add any appreciable efficiency to the repair effort.

Restoration of service once repair has been completed involves reenergizing the system and checking to see if all customers are restored. In radial systems prevalent in rural areas, laterals can often hide equipment damage that was not detected during the initial line patrol and these situations are the ones in which customers can be overlooked at restoration time. Polling meters in these cases would be helpful to detect that damage.

In urban systems, radial feeds are not so common and hidden equipment damage less likely. Because these systems are often looped and interconnected, more time is spent at the outset of repair to sectionalize the faulted section by opening and closing switches in order to restore power to as many customers as possible. The repair work then proceeds on a much reduced part of the system involving less customers than on a radial feed system so that the problem of ensuring that all customers are restored is much reduced. For example, cars hitting padmount transformers in suburban subdivisions is a common cause of outages. In these cases, the line protections may operate to isolate a fairly large section but once the damaged equipment is located, switches in transformers on either side of the damaged one are opened and power is restored to all but those customers fed from the damaged unit. Since only about 10 customers are then involved in the outage and all are clustered around the damaged transformer, it is relatively easy to ensure that all have been properly restored at the end of the repair phase.

Nonetheless, in some utilities, meter polling would be more efficient and could save a return visit to restore a customer that was overlooked. The cost of having a crew return to an outage location to restore power to overlooked customers is estimated to be $200 per event.

Quantifying the number of these events in order to arrive at an average savings per customer is fairly difficult but reliability statistics can provide some guidance. For example, in 1997 a total of 19,709 outages in a customer base of 3,880,705 were reported by 21 urban utilities surveyed[10]. If 1% of these outages resulted in an overlooked customer requiring a return crew visit at a $200 cost then the cost per customer per month would have been about $0.01 [(19709 * .01 * $200)/3880705/12]. If the frequency of overlooked customers was much greater, say 10% then the cost per customer per month would have been $0.10.

For more rural utilities, the number of outages is generally higher and similar calculations based on 23 utilities reporting 201,215 interruptions in a customer base of 14,788,580[11], the comparable cost per customer is about $0.03 per month at the 1% frequency rate and $0.30 at the 10% rate.

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[10] *1998 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities Composite Version,* Canadian Electricity Association, May 1999, p.46

[11] IBID p. 58

Many utilities would dispute that the frequency of overlooked customer events is anywhere near 10%. Urban utilities in particular would also point out that the outage numbers reported include some interruption types that are unlikely to result in a missed customer. Outages caused by failure of the bulk supply system, for example, do not cause local equipment failures that can lead to overlooked customers. Planned outages are another category in which a utility knows in advance exactly which customers will be affected so that overlooking one on restoration is less likely. These two types of outage comprised almost half the interruptions reported by urban utilities in 1997[12]. If this is taken into account in the calculations above, the cost per customer per month would be about half of that stated.

Because no data exists to either confirm or deny the frequency of overlooked customers that could be saved by automatic meter polling to confirm restoration, any number used will be arbitrary. The best that can be said is that there is a benefit to being able to remotely confirm service restoration and that benefit will vary depending on the LDC's service territory characteristics. For the purposes of this report, the cost study group set the value at $0.05 /meter/month.

Other studies suggest the value is higher. CERA, for example, estimates it between $0.06 and $0.31 USD per meter per month. In the absence of detailed information on how those numbers were arrived at, the cost group decided to rely on its own analysis.

Benefit #13 – Distribution System Optimization and System Planning Support

These benefits are related to the ability of LDCs to design and operate their systems efficiently, which may be enhanced with finer demand data at the customer level. The theory is that aggregation of customer data will permit more accurate sizing of system equipment and eliminate oversizing caused by uncertainty. Unfortunately, load uncertainty plays a very small part in the design and sizing of components in a distribution system and utilities have well-established methods in place to validate their design assumptions. For example, transformer selection is limited by the sizes that are available from manufacturers. A designer chooses the size that is next largest to the expected customer load. Finer data resolution would not change that choice because the interval between available transformer sizes is larger than the error that could be resolved by better data.

Line equipment is also sized according to broad design criteria that would not be affected by better individual customer load information. Conductors, for example, are sized to carry a full feeder load regardless of actual customer load at the time the line is built. This is done because the cost of reconductoring an undersized line in the future is much higher than the cost of investing in heavier conductor at the outset. The design strategy also allows for one circuit to backup another that might be interrupted by providing double the expected capacity in each. Thus, lines that are expected to supply 300 amps of load may be sized to carry 600 amps so that interruptions to other circuits can be mitigated. This kind of system design consideration does not depend on finely resolved customer data and would not be assisted by it.

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[12] IBID p.47 Loss of Supply = 4.4% and Scheduled Outage = 44.6%

Optimization of system operations involves balancing feeder loads and maintaining voltage. Balancing minimizes line losses, which are proportional to the square of current and are inversely related to conductor impedance. In radial systems load cannot be transferred between circuits because they don't intersect. Balancing in these cases is usually restricted to trying to put the same load on each phase of a three-phase system. This is done by estimating customer loads by applying a load factor to either the installed transformer capacity or customer monthly consumption data and then distributing the line drops to transformers among the three phases Accurate data resolution at the customer level can assist in this exercise by eliminating the guesswork involved in load factors and by automating the data analysis part of the job.

In an urban system that is usually looped and interconnected, balancing of feeders can be done by judicious placement of line switches. This is done by measuring feeder loads and voltages at various points in the circuit often automatically by a SCADA system. Switches are then opened and closed to add or subtract load from a feeder. None of this would be assisted by finer resolution of customer data because it is conducted using feeder level data that is already available from instruments installed at feeder breakers and at points downline.

Investments in system expansion are also decided on the more global data derived from feeder and station loadings. This data already reflects the coincident demand of all customers on those facilities and although it could be produced by aggregating customer data, it is questionable why anyone would want to do that when the same information can be read off a station meter easier.

Although there may be opportunities for detecting equipment overloads sooner through aggregated customer data, using it for system planning and optimization purposes is not expected to yield any appreciable advantages over the existing methods at least for urban utilities. Rural radial systems, as discussed above, may realize some benefits in the form of better phase balancing and in supporting decisions to build interties to transfer load from one feeder to another. The value, however, is impossible to generalize and will depend on the individual circumstances of the LDC.

Appendix C-2: Smart Metering Costs

Table 2

	Category	Reason for Cost	Value	Operating $/month	Possible Mitigation
1	Increased cost of meters	Meters are more expensive technological obsolescence may drive shorter depreciation period	Combined cost of meter, AMR and data systems est. $250/meter See chartnotes		
2	Communication system	Communication system is a new requirement for meter reading	Included in #1		
3	AMR system OM&A	New cost not presently in the rates includes meter trouble reports	Estimated $0.20/meter/month based on 1% of capital deployed	$0.20	
4	Breakdown of Installation Costs included in #1 above	1. Remove existing meter and install new smart meter	Est. $15 per residential meter $50 - $200 per general service meter included in #1 above		Use mass deployment strategy wherever possible - avoid custom installations
		2. Damage to customer equipment expected with semi skilled labour installing meters	Meter base replacement est. $350 panel replacement up to $1000 See Chartnotes		Training of semi skilled workers Use ESA certified contractors for inside meter conversions to avoid inspection costs and delays
		3. Inventory storage and handling may exceed LDC capacities	Unknown		Outsource to contractors with experience
		4. Overtime costs for skilled trades may be high if general service customers require meter change after normal business hours	Applies primarily to 3 phase units single phase units expected to require only short interruption		
		5. Training for staff on new meters, rate plans, AMR systems, data presentment etc	May be significant in initial deployment period		Joint training with other LDCs

Appendix C-2: Smart Metering Costs – Cont'd

	Category	Reason for Cost	Value	Operating $/month	Possible Mitigation
4	Breakdown of Installation Costs included in #1 above – Cont'd	6. Internal wiring changes may be needed for some conversions e.g. Some customers have separate meters for heating and hot water; some are inside meters	Cost of revising wiring and changing inside meter to outside can be significant		Customer contribution Leave inside meter in place
5	Meter Regulation Costs	1. More frequent reverification required for electronic meters and sample size may be larger	Estimated $0.04 /meter/month	$0.04	Technological obsolescence may retire meter before reverification.
		2. Time stamping of demand in meter	Additional meter cost		Use time stamp in meter for demand
		3. Reconfiguring TOU buckets may trigger reverification	Estimate $60 per meter		MC policy allows remote reprogram Two-way comm system needed
		4. Present MC policy requires testing in accredited test facility	Removal costs est. $50 per meter		
		5. MC policy requires demand display	Additional meter cost		Need MC policy change to relax mandatory display requirements

Appendix C-2: Smart Metering Costs – Cont'd

	Category	Reason for Cost	Value	Operating $/month	Possible Mitigation
6	Data Management	1. Data storage	Est. $0.50 /meter/month	$0.50	Based on IMO scaled costs
		2. Data editing and validation	Depends on code requirements est. $0.01 /meter/month	$0.01	Permit automatic data plugging to minimize labour costs Get change in MC policy requiring storage of data for life of meter
		3. IMO reconciliation	More data and daily quantities may increase cost		Minimize requirements – reconcile monthly
		4. EBT costs	Increased data potentially 100 to 1000 times present cost	$0.02	Minimize RSC requirements for low volume customer data transfers Charge retailers for enhanced data Provide alternate pathways for data
		5. Meter reading	Varies with volume of reads Est. $0.10 - $0.60 meter/month	$0.15	
7	Customer Service	1. Usage presentment	Varies with frequency of updates and quality of presentation required est. $0.50 /meter/month	$0.50	Minimize updates and keep format simple
		2. Call center	Initially higher calls due to new rates est. 10% increase		Customer education

Summary of Base System Costs

Total New Capital cost/month	*based on amortizing capital cost of $250 over 15 years*	$2.47	Includes gross up for PILS and credit for existing meter cost See Chartnotes for details
Total Operating Cost/month	*sum of operating costs in Table 2*	$1.42	
Total operating savings/month	*sum of operating benefits in Table 1*	-$0.39	
Net cost per month residential		**$3.50**	

Appendix C-2: Smart Metering Costs – Cont'd

Enhanced System Costs Not Chargeable to Customers in LDC Rates

	Category	Reason for Cost	Value	Operating $/month	Possible Mitigation
8	Multi utility read conversion	Adding water and/or gas reads to remote system will require internal wiring on customer premises	Unknown – depends on technology		LDCs may want to offer service bureau approach to water and gas utilities
9	In home display module	May be desirable for customer feedback of consumption	Est. $100 installed cost		Specify other method of feedback Leave display option for retailer Value added feature
10	Load control capability	May be desirable to meet DR objectives	Unknown - depends on technology		Leave for retailers or LDCs to offer as competitive product
11	Bulk Metered Facilities submetering costs	Estimated 1.7 million consumers are bulk metered - may be desirable to include in project	Submetering requires owner to abide by Measurement Canada metering rules – costs are significant		
12	Conflicts with DR objectives	Fixed price retailer offerings w/o load control and LDC equal payment plans may defeat load shifting	Unknown but could be significant problem if customers elect to bypass real time pricing		Eliminate equal payment plans? Better customer feedback
13	New data uses	LD engineering, operations uses Retailer service design - costs arise from increased metering system functionality requirements	Unknown – depends on usage will require new data handling and interface systems		Charge costs to benefiting party May require RSC change to limit data to retailer requirement
14	Load aggregation and dispatch	Verification and settlement system will be needed	Unknown		Charge cost to aggregator

Chart Notes for Table 2 – Smart Metering Costs

Some costs as numbered in the above table are further explained here.

Cost #1 – Increased Cost of Meters and AMR System

For most customers, smart meters will cost more than those that are presently used. The exception is for interval customers who will continue to use their existing meters. Depending on the overall metering system configuration, meters for residential and small single phase general service customers can vary upwards from about $70 for a basic electronic meter with a communication device to $125 for a more functionally capable meter with some time of use or interval storage capability. The automated reading system, data storage system, complex billing engine and various interfaces necessary to integrate the smart metering system with existing LDC systems are all additional costs. Taken together these costs are expected to be about $250 per meter. Offsetting this is the cost of metering presently supplied. Survey data suggests that this cost is about $50 per residential customer. On a monthly basis the cost of new smart metering capital is expected to be $3.00. This figure was arrived at by assuming a 15 depreciation period for smart metering capital, gross up for PILS at 43.5% on the equity portion of 9.88% factored for a 55:45 debt equity ratio and 7% for debt. An existing meter capital cost offset of $0.53 was arrived at by assuming the current meter capital depreciation period of 25 years and the same gross up and debt factors as for new capital. Together the new and old capital costs net out to $2.47 per month.

Meters for general service customers that are currently demand metered may present a challenge because of limited availability of a smart meter equivalent of the existing demand meters. Four options appear to exist to serve these customers:

1. Retrofit existing electronic versions of demand meters to obtain hourly data
2. Install interval meters with MV90 or equivalent interrogation
3. Install consumption meter only and drop demand billing altogether
4. Bill demand on an alternate basis than demand reading

The first alternative has some limitations for data collection as the meter will have to be read hourly in order to establish the peak hourly demand for billing. This raises the issue of missed reads and how to deal with them. The second alternative would require that the more expensive interval meter be installed for all general service customers down to the demand limit of 50 kW. The cost of doing this is high and there are questions about the ability of the MV90 or equivalent interrogation system to handle the increased number of units in service.

The third alternative is to restructure the transmission and distribution billing rates so that billing is based on consumption not demand.

The fourth alternative preserves a demand charge but fixes it on some objective basis that does not rely on a meter reading. For example, demand charges could be based on the nameplate rating of the transformer installed to serve the customer.

Alternatives #3 and #4 would both eliminate the need to measure demand in the meter and allow a wider range of meter availability for the general service group over 50 kW but below the threshold for using an interval meter.

Cost # 4 – Meter Regulatory Costs

Reverification costs arise from the need to periodically test meters for accuracy. Measurement Canada regulates electricity meters and specifies the frequency and test method to be applied in reverifications. Currently, electromechanical meters must be tested after being in service for 12 years (initial seal period) after which they are sampled to determine if accuracy has drifted. The sample size is about 3%. Electronic meters have an initial seal period of only 6 years and sample sizes are being determined by the regulator in pilot testing presently ongoing. The sample size is expected to increase with some industry observers suggesting it may go as high as 15%. For the purposes of this study the cost group assumed that sample size would double from current electromechanical meter requirements to 6%.

Assuming an even deployment of smart meters over 6 years, the annual population coming up for reverification in 2012 would be about 650,000 (1/6 x 3.9 M residential meters). At a sample size of 6% the number of meters that would have to be removed and tested would be 39,000. The cost to retrieve a meter from its field location is estimated to be $50 and the cost to test an electronic meter is estimated at $10 (for simplicity the same numbers are applied to electromechanical meters although the cost of testing these is only about half that of electronic meters). Therefore the total cost of compliance sampled smart meter reverification would be $2,340,000 annually.

The comparable cost for electromechanical meters with a 12 year seal period and a 3% sample size would 25% of this (3.9 M meters / 12 years x 3% sample size x $60 per meter tested = $585,000).

The additional cost of reverifying smart meters is the difference between $2,340,000 and $585,000 = $1,755,000 or about $0.04 per customer per month.

Larger customers are not compliance sampled but are 100% tested at the end of the seal period which is already 6 years. Therefore, there will be no additional costs to reverify smart meters installed for these customers.

Cost #5 – Installation Costs

Damage to customer owned equipment may result from the fact that residential meters will probably not be installed by skilled trades but rather by purpose trained temporary workers. This workforce will probably be given basic instruction on how to remove a residential meter and install a new smart meter. It is likely that some mechanical damage will result either from mistakes in pulling the meter out of its socket or from deterioration and mechanical stress on the internal electrical connections of the socket. Some customer meter bases need replacement and this work will have to be done by skilled trades at an estimated cost of about $350 per occurrence.

Another source of damage to customer equipment might arise from the need to operate the customer's main disconnect switch because the load on the meter is above what can be safely interrupted by physically pulling the meter out of its socket. Some old switches that might not have been operated in many years can be expected to fail in these circumstances and if replacement parts for the particular panel are no longer available it might be necessary to change out the panel. This can cost up to $1000 per occurrence.

Inside the building meters might also lead to extra installation costs if the LDC takes the opportunity to eliminate them and install the new smart meter outside. In this case internal wiring modifications may also be necessary. LDCs can avoid these costs by installing the smart meter inside the building but this might not always be possible because of communication limitations.

If the customer was part of previous electrictiy promotion schemes, it is possible that separate meters were installed for electric heat and/or hot water heaters. If these are consolidated into one smart meter, additional wiring and installation work will raise the cost of the smart meter installation. The LDC may opt to simply replace the existing installations with smart meters rather than consolidate but in that case two meters would be required which would increase the cost of the installation.

Overtime costs are expected to be high for converting small commercial and industrial customers to smart meters. Those customers with socket mounted meters will require an outage to convert them and many business customers object to interruptions during business hours. If conversion is necessary after hours then overtime costs for the trades doing the work will be incurred.

Cost # 7 – Customer Service

Feedback of consumption data to the customer is necessary to provide the information that is expected to drive load shifting behaviour. The Minister's directive specifies that this feedback needs to occur daily and the cost of assembling data in a format useful to customers may be high depending on the quality of the data required, the level of sophistication in the presentation and the means used to present it. If, for example, unedited data converted into a simple rolling bar graph of daily consumption posted on a website is all that is required the cost might be reasonable. If the data has to be edited for missing pieces and verified or if the presentation includes pricing information and multiple graphs comparing to other customers or historical usage then the price will increase.

Call center costs are expected to increase initially by up to 10% because of the more complex time billing involving daily consumption and time of use or hourly prices. The estimate is based on a deployment program over four to five years and the likelihood that at least 1/3 of the customers receiving smart meters in that year will call with a question about installation or billing. Ultimately, it is expected that after customers become familiar with the new system calls will decrease because of better meter reading accuracy and less errors on bills.

Appendix C-3: Stranded Costs

Table 3

	Category	Reason for Cost	Value	To Whom	Possible Mitigation
1	Meters	Existing 1 phase and 3 phase meters will be obsolete	Estimated from survey data $110 per customer Total approximately $473 M nominal	LDC with recovery from Customer & others	Resell units abroad – possible for GS meters but transportation may exceed value for residential
2	Meter reading equipment	AMR will replace		LDC and meter reading company	
3	Contract liquidated damages	For early cancellation of multi year meter reading contracts	Not expected to materialize for any but first LDCs to convert	LDC	Renewals of contracts should consider smart meter deployment schedule
4	Sub metering systems in bulk metered facilities	Not currently part of smart meter project – cost will materialize if project expanded	Approximately 1200 submetering systems in province	Private owners	Not part of project so mitigation unnecessary at this point
5	Customer Information Systems	If systems are not capable of smart meter billing and customer service	UCC if any remaining plus market transition costs in deferral accounts estimated $53 M from survey data	LDC	New front end data storage system may do billing calcs and send up to CIS – interface will be required from CIS vendor to prevent stranding
6	Settlement Systems	Systems were purchased/leased or services contracted for to supply NSLS – may not be needed	Unrecovered transition cost included in CIS estimate above contract cancellation fees	LDC	Settlement systems may be able to develop into front end storage and data management systems
7	Labour	Meter readers and check read staff no longer needed with AMR systems	Varies with collective agreements may involve redeployment, training costs or termination costs	LDC	Negotiate strategies with unions early to maximize alternatives
8	Joint utility reading cost sharing	Applies to LDCs that read meter jointly with water and/or gas	Cost of manual read for water or gas utility may double when electric reads are done by AMR	Municipalities Gas distributors	Early notification to permit other utilities to participate in AMR or make other reading arrangements

Appendix C-3: Stranded Costs – Cont'd

	Category	Reason for Cost	Value	To Whom	Possible Mitigation
9	EBT hubs	To extent they are unable to adapt to smart metering requirements or interface with data storage systems if do not meet smart metering requirements	Undepreciated capital cost of system	EBT hub owners	Upgrade EBT; minimize data transfer requirements for residential customers Prepare interface systems
10	Interval Meters		Est. $1,500 per interval customer	Interval customers	Continue using existing interval meters with MV90 data reading

Appendix C-4: Recovery Options for Smart Meter Costs

Table 4

Option #	Features	Fairness	Rate Impact	Timeliness	Efficiency	Adverse Effects
1 – New	Include forecast of capital and OM&A Costs in ratebase for 2006 allocate fixed charge equally per customer	Allocation may not match asset deployment – cost of GS meters is higher than residential customers will pay Disproportionate share of costs Cost impact on interval customers is nominal	Full cost of deployment will be in rates from outset of program May produce rate shock with other 2006 inclusions and residential rates may be higher than with other options	LDC recovery matches deployment All customers begin paying at same time No deferral accounts	Easy to calculate rates LDCs recover costs as incurred Requires true up between forecast and actual costs Facilitates regulator review of costs and benchmarking between LDCs	Small customers would bear higher proportion of costs Distorts cost of service for metering between residential and GS classes
2 – New	Include forecast of capital and OM&A Costs in ratebase for 2006 allocate equal fixed charge by customer by class	Better alignment of costs and benefits between classes No link to consumption so does not assist DR objectives	Full cost of deployment will be in rates from outset of program May produce rate shock with other 2006 inclusions but residential rates will be lower than in option #1	LDC recovery matches deployment All customers begin paying at same time No deferral accounts	May be difficult to apportion AMT costs if serve more than one class LDCs recover costs as incurred Requires true up between forecast and actual costs Facilitates regulator review of costs and benchmarking between LDCs	Interval customers realize system efficiency benefits without having contributed to smart metering cost recovery

Appendix C-5: Recovery Options for Smart Meter Costs – Cont'd

Option #	Features	Fairness	Rate Impact	Timeliness	Efficiency	Adverse Effects
3 – New	Include forecast of capital and OM&A Costs in ratebase for 2006 allocate fixed charge by customer Adjusted for annual consumption	Better alignment of costs and benefits within classes	Full cost of deployment will be in rates from outset of program May produce rate shock with other 2006 inclusions	LDC recovery matches deployment All customers begin paying at same time No deferral accounts	More difficult to set up and administer for LDCs and Regulator Same comments as #1 and #2	Customers with electric heating may pay more May penalize disadvantaged groups leading to social policy interventions e.g. DSM programs
4 – New	Include forecast of capital and OM&A Costs in ratebase for 2006 allocate costs volumetrically by consumption	Aligns cost recovery with DSM objectives for conservation Does not distinguish when consumption occurs so does not provide load shifting incentive	Proportional to usage Low volume users will be impacted least	LDC recovery matches deployment All customers begin paying at same time No deferral accounts	More difficult to forecast because of consumption volatility True up and adjustment mechanism will require closer monitoring More regulatory effort to administer	May penalize customers who cannot lower consumption
5 – New	Include forecast of capital and OM&A Costs in ratebase for 2006 allocate costs volumetrically by demand	Aligns cost recovery with DR objectives but unless coincident demand is used, does not incent load shifting	Proportional to usage Rate design very complex	Uncertain recovery period because related to demand Customization of recovery start possible among LDCs but not within an LDC	Hard to forecast, hard to measure unless interval meters are deployed Difficult for customers to understand Rate structure	TOU meters may not be capable of providing data May contravene Measurement Canada rules for time stamping of demand in meter

Appendix C-5: Recovery Options for Smart Meter Costs – Cont'd

Option #	Features	Fairness	Rate Impact	Timeliness	Efficiency	Adverse Effects
6 – New	Include forecast of capital and OM&A Costs in ratebase for 2006 allocate costs volumetrically by coincident demand	Most closely aligns cost recovery DR objective to shift load off peak	Proportional to usage May require significant redesign of rates	Uncertain recovery period because related to demand Customization of recovery start possible among LDCs but not within an LDC	Same as in previous option but in spades	Same as previous option
7 – New	Allow recovery in rates as meters are deployed for any of above options	Requires LDC to finance costs until rebasing aligns cost recovery with potential benefits	Rate impact would be deferred until meters actually installed	Delayed recovery of costs More frequent rebasing Higher regulatory costs	Separate rate structures for those with and without smart meters in same customer class – more complicated rate setting and CIS management	
8 – New	Any of above but allowing exemptions for customers that will not realize benefits	Recognizes limited potential benefit for low volume or seasonal customer Avoids high cost installation areas e.g. Cottage country and other low density areas in HONI territory	Billing could be a problem LDC could maintain NSLS system or Board could require some fixed price contract with retailer as condition of exemption.	Would not apply to exempted customers	Separate rate would be needed to recognize no smart meter	Many customers might complain at not having the same option

Appendix C-5: Recovery Options for Stranded Costs

Table 5

Features	Fairness	Rate Impact	Timeliness	Efficiency	Adverse Effects
Equal fixed charge per customer based on total stranded costs	May impose disproportionate share of costs on residential class – GS class has higher $ value of stranded assets	Flexible – can be amortized to fit rate objectives	Permits prediction of when retirement will be complete Customization of recovery start possible among LDCs but not within an LDC	Easily understood, certainty, low transaction costs because no forecasting or true up required	
Equal fixed charge per customer based on customer class stranded costs	Those who contribute to costs will bear them but interval customers will escape any burden while sharing in social benefits	Flexible – can be amortized to fit rate objectives	Permits prediction of when retirement will be complete Customization of recovery start possible among LDCs but not within an LDC	Easily understood, certainty, low transaction costs because no forecasting or true up required	
Fixed charge per customer as in #1 or #2 but adjusted for customer consumption	Allocates more of costs to heavier users of system would permit allocating costs to large interval customers	Flexible – can be amortized to fit rate objectives	Permits prediction of when retirement will be complete Customization of recovery start possible among LDCs but not within an LDC	More complicated to set up Erodes linkage between who used stranded asset and who pays for it	Will impose higher costs on groups bound to electric heating
Equal volumetric charge based on total stranded costs	Same as #1 plus may impose excessive burden on customers who are unable to mitigate e.g. Electrically heated homes	Proportional to usage	Uncertain recovery period because related to consumption Customization of recovery start possible among LDCs but not within an LDC	Not as easily understood/accepted Higher transaction costs because of need to forecast and true up	May impose high costs on disadvantaged groups requiring intervention for social assistance

Appendix C-4: Recovery Options for Stranded Costs – Cont'd

Features	Fairness	Rate Impact	Timeliness	Efficiency	Adverse Effects
Equal volumetric charge based on customer class stranded costs	same as #2 and may impose excessive burden on customers who are unable to mitigate	Proportional to usage	Uncertain recovery period because related to consumption Customization of recovery start possible among LDCs but not within an LDC	Not as easily understood/accepted Higher transaction costs because of need to forecast and true up	
Convert to regulatory assets and continue existing depreciation until retired	Would be seen as fair by customers because maintains status quo and no comparator	None	Meter costs are primarily recovered in fixed charge so prediction of retirement should be possible	Might require 15 years to retire Could be intergenerational transfer of costs	May limit future rate flexibility
Transfer to OEFC and recover as part of stranded debt	DRC is volumetric charge so allocates higher costs to heavier users Large customers will complain that they are paying for residential stranded assets	Proportional to usage Can be adapted to rate objectives	Uncertain recovery period because related to consumption	Securitization costs may be lower for OEFC than for LDCs	May adversely affect Provincial debt rating

Appendix D. System Requirements

Appendix D-1: Exceptions to Customer Categories

Not all metering can be directly replaced with smart meters. A number of legacy issues need to be resolved.

Older Installations
A number of older houses have 120V single-phase supply rather than 120/240 V supply. These will need to be re-wired or the meter socket modified before a smart meter can be installed. A small number of homes have two services one for electric heat and one for electric lights, each separately metered. Two smart meters will be required or the installation can be rewired to combine the services behind one meter.

In some urban areas, older buildings have been converted from commercial operations and factories to condominiums. The existing 600V phase supply will require a special meter or conversion to 120/240 V.

Large and Small Consumers
A small number of consumers with demands exceeding 50 kW are supplied with residential style single-phase service. The consumers are presently billed on energy and demand. They will require a smart meter with demand capability added.

A small number of consumers have demands less than 50 kW have polyphase supply. A Group 2 smart meter will be required in place of the usual Group 1 residential meter.

2.5 Element Meters

Existing 2.5 element meter installations come in two forms: direct (socket) connected and transformer rated. All Ontario utilities have plans to replace 2.5 element meters with three element equivalents:

- Direct connected meters: will be upgraded to 3 element meters when the meter is replaced for reverification.
- Instrument transformer rated meters will be upgraded when the supply facility under goes substantial upgrading or refurbishment involving outages to replace power transformers, switchgear etc.

The report proposes:

- Direct connected meters be upgraded to three elements as part of the smart meter roll out
- Instrument transformer rated 2.5 element installations should remain in service until the power transformer or switch yard is upgraded or refurbished. If a 2.5 replacement is not available, the meter may be replaced with a two-element

meter and the current transformers reconfigured to a delta connection at the test block.

Ancillary Devices for Feedback of Consumption or Multi-Utility Capability

Any ancillary devices connected to the meter for in-home or local feedback on consumption must be connectable to the meter without breaking the meter seal or removing the meter.

If the meter is included on the path taken by water and gas readings during data collection, the connection and disconnection of these information sources to the meter must be possible without breaking the seal on the meter.

Rationale: Provision of value added energy services will be facilitated if the meter need not be removed and or replaced when new feedback appliances become available. This may be accomplished through the use on an inter-base between the meter and the socket.

Prepayment Meters

At the utility option, a smart meter may also include prepayment features.

Rationale: Prepayment meters can play a significant role in making consumers aware of the cost of energy and have demonstrated energy savings in some applications. Nothing should prevent a smart meter conforming to requirements specified above from also employing prepayment technology if the utility wishes to deploy it.

Recommendations: Existing prepayment meters should remain in-service. Any new prepayment meters installed should comply with the full requirements of a smart meter.

Net Meters

In addition to meeting any future requirements for net meters that may be specified by the province, every net meter must also be able to provide all of the functionality required of a smart meter.

Rationale: Net meters are meters which are intended for used in residential applications where small local generation on the load side of them meter may result in a supply of energy from the home to the distribution system. During those periods when the home is consuming the owner would like to take advantage of the opportunities offered by smart meters. For this reason a net meter must provide smart meter functionality in addition to net metering capability.

Net meters are a specialized application of the smart meter and may require different marking and specialized verification for net metering purposes. Some net meters have only one register, which increases its readings when the residence consumes energy and decreases when the residence generates. Others have two registers, each separately recording consumption and generation.

Since requirements for net metering and billing are undefined at this time, it is recommended that that utilities select and deploy smart net metering as required to match local policy.

Appendix D-2: Minimum Functionality Specification for Meters

The proposed minimum requirement for a smart meter is:

Measurement Canada Approval

Every smart meter must be approved by Measurement Canada prior to purchase.

Rationale: A requirement arising from the *Electricity and Gas Inspection Act*.

Minimum Accuracy Requirements

A smart meter must comply with the accuracy requirements of LMB-EG-07 or its successor.

Rationale: LMB-EG-07 is an internal standard enumerating Measurement Canada's requirements for type approval. LMB-EG-07 may be replaced in the future with international requirements arising from efforts to harmonize ANSI and European Union standards.

Read Resolution

The minimum read resolution for metering data obtained from data collection system or read from the display is 0.01 kWh. This applies equally to interval data and time-of-use/critical peak pricing registers.

Rationale: Traditionally meters have been read the nearest kWh (or in some cases 10 kWh). This was adequate for billing periods covering several months where any fractions of a kWh left over are carried over to the next billing period. Typically the rate in both periods was the same.

Billing periods in the future will be much shorter, hours rather than months. Better read resolution ensures that the maximum volume of energy passed on to the next billing system will be small, limiting the maximum pricing error to fractions of a cent.

Socket Compatibility

A utility purchasing smart meters must account for physical compatibility when ordering meters for direct connection. When placing orders for meters each utility will aggregate meter counts by socket type.

Rationale: Several different types of sockets are used by Ontario utilities. Variations allow for differences in the number of elements, voltage of application and number of jaws.

The full range of socket types used in each utility may be available from every vendor limiting the choice of vendor. Some utilities may upgrade from one socket type to the other. Other sockets may have to be modified to accommodate a smart meter.

Hourly Profile Data

The smart metering system must be capable of producing hourly consumption data.

For:

- *Residential Consumers: The smart metering system must be capable of at least 1-hour profiles*
- *General Service Consumers 50 – 200 kW: The smart metering system must be capable of at least 1-hour profiles*
- *General Service Consumers 200 – 1000 kW: An interval meter capable of 15-minute intervals is required.*

This is in addition to any other applicable or required quantities and values that may be required of the smart metering system.

Rationale:

- Hourly consumption data may be obtained from a traditional interval meter comprising on-board memory, optical port and modem; or a smart meter fitted interval registers or a single register meter read hourly.
- Processing of hourly data in the head end system allows flexible shifting to seasonal, daily time-of-use as well as fixed and variable critical peak pricing, all without removal the meter. On the other hand, the volume of data to be transmitted can be reduced by "compressing" hourly data into time-of-use and critical peak pricing registers at the meter. Since the automated meter reading system can carry both types of data, the distributor will decide which method will be used.

Demand Functions

If the distributor's board approved rate order includes a demand charge, the time stamping mechanism must be approved by Measurement Canada.

Rationale: While accuracy of clock synchronization is not essential, accuracy in determining the duration of the interval is, since both the numerator and denominator must be accurate to arrive an accurate determination of average demand. Time synchronization is less important as it affects price not quantity.

Power Factor Billing

If the existing rate order includes charges for power factor, the meter must record both active and reactive or active and apparent interval energy.

Rationale: Active and reactive energy readings or active and apparent energy readings are used as inputs to the power factor calculation.

Emergency Reading Capability

Alternate means must be provided for obtaining any data stored in meter/AMR module or collector memory.

Rationale: In the event of a dispute or sustained malfunction of the communication, system data within the device will need to be extracted.

Meter Clock

Any clock within the meter must be capable of synchronization to the national time standard, without visiting the site, to a tolerance of 30 seconds.

Clock time must be maintained during a power outage. During an outage, clock time must drift at a rate less than 360 seconds/year.

Rationale: Accuracy of time stamping ensures the correct price is applied to measured consumption.

Access to Internal Battery

Any batteries inside the meter must be capable of providing reliable service for the entire initial seal period or be capable of replacement without removing the meter seal.

Rationale: If the battery will not last the entire seal period, breaking the seal will force early reverification.

Meter Diagnostic Information

The data collection system must report any and all anti-tampering and diagnostic messages generated within the meter.

Rationale: Remote access to the results of self-diagnostic tests and alarms is required to monitor the health of the installed meter population.

Security of Meter Data

Access to information and firmware stored in the meter must be controlled by password or other protection.

Rationale: Only authorized personnel should be able to change internal readings or reprogram meter functions. Access control ensures any change made is legitimate and traceable and that the integrity of stored data is maintained.

Meter Programming Software and Vendor Support

The vendor must make available any software required by an accredited meter verifier to program and verify the meter, including training and technical support.

Rationale: Meters must be individually programmed during the reverification process.

Initial Verification

The vendor must be able to verify and seal, or arrange for verification of, new meters.

Purchasing utilities may specify that meters be delivered either sealed or unsealed by the manufacturer.

Rationale: To facilitate rapid deployment of smart meters, most utilities expect to purchase meters that are verified, sealed and ready for service.

Distribution System Reclosure

The meter must be immune to reclosure of distribution system protections. Data and clock time must be secure during and after the reclosing sequence.

Rationale: A reclosure is an outage of 0.1 to 2 second caused by tripping of a protective device between the meter and the supply station. Up to four separate reclosings may occur over the 10 to 30 second period during which the faulted portion of the distribution system is isolated. Operation of a protective device typically affects hundreds to thousands of meters during each reclosing sequence.

KYZ Pulse Initiator

Every pulse initiator supplying information to the smart meter system must have a demonstrated mean time to failure such that 99% of pulse initiators will reliably transmit data for twice the initial seal period of the meter.

Reliability standard required: The pulse initiator must add, or fail to transmit, no more than 1 pulse in 10,000.

Rationale: Reliable transfer of consumption information from the meter to the smart metering system is essential for accurate and reliable billing of consumers.

Appendix D-3: Additional SMS Functions

These services are not recognized as base level SMS functions. LDCs that choose to include these items as a necessary requirement in their SMS selection must cost justify any additional expenditures that are incurred for including this in their SMS selection and implementation.

Remote Service Disconnect Feature

Remote Service Disconnect is performed through the purchase and installation of an ancillary sleeve device that fits between the meter and the meter socket. A signal can be sent from the utility operations centre and/or SMDCC to turn the power off at a customer's home for non-payment or in the event of a move out requirement. SMS vendors state if a disconnect unit is available for installation and operation with their SMS. LDC's must cost justify the investment in this feature and that the delivery of this feature has social and operational benefits that can enhance the cost justification process.

Remote Service Reconnect

Remote Service Reconnect is completed using the remote service disconnect unit. Certain liabilities exist in reconnecting service remotely and at the present time it is not recommended that LDC's consider implementation of this feature until clear processes and customer confirmations have been approved that will alleviate the liability issues. This is not recommended as a service option to be offered at the present time.

Tamper Detection

A certain level of tamper detection exists in all SMS. Reverse disk rotation, intermittent power outages, communication link termination, etc. are some of the features offered in varying levels of tamper reporting sophistication in all SMS. While not a mandatory option, LDC's should know what can be provided with the SMS they select.

Note: If the tamper instance, such as communication failure, directly impacts the read acquisition level of 95%, then LDC's must insure critical reporting capability is available to find the problem and resolve it before read transmissions are impaired.

Outage Detection/Restoration

LDC's may account for significant operational savings in using the SMS to report power outages:

- With the read transmission in order to log power quality and service quality levels
- During an extended outage period in order to map outage by specific customer

- Immediately in order to know when a customer calls in if it is a line side or customer induced issue

Outage detection features may be resident to some degree in all SMS. LDC's are encouraged to find out what capability is present in the SMS they are selection, however this feature is not mandatory and if a system is purchased specifically to acquire this feature there must be specific customer/operation benefits identified that will provide a measure of payback for acquiring a SMS with this feature

Outage Restoration

Even fewer SMS provide outage restoration capabilities, however it does exist in several of the qualifying SMS. In this case the SMCM will call in randomly to confirm they now have power or the system operator can query specific SMCM to determine if they are energized or not.

Prepayment

Prepayment can be instituted using a SMS. Primarily information flows to the SMDCC and is compared in the SMS or in the CIS for ensuring customer balance information is tracked and debited as usage occurs based on the information collected every 24 hours. Customers must be installed with a visual display that also provides usage information and computes dollars spent and balance remaining.

Most SMS will require an upgrade beyond that used for other SMS functions. LDCs must prove that the functionality and additional cost to provide this service are a benefit socially to their customer base or demonstrate an additional and measurable benefit to utility operations.

Net Meters

Net metering is not a minimum requirement of the SMS. Some SMS can provide this functionality as a default and LDCs can consider this as an additional benefit if they happen to select a system where this is a base service option.

SMS Compatibility and Ability to Interface to Gas and Water Meters

LDC's that read water meters in their service territory may wish to include an option for the municipality or gas utility to be included in the SM initiative. If this is the case, the LDC must develop a cost model for reading the meters for the gas or water utility or some cost sharing of the system for ensuring that this advanced capability can be provided with now additional burden to the electricity customer.

If this is a viable business option, SMS selection and network configuration of the must be developed that ensure adequate capacity for the data collection and transmission of smart water/gas meters to be read by the same electric SMS.

Functionality specifications and the data warehousing, data security, etc. configuration of SMS that addresses gas and/or water meter reading requirements, in conjunction with SM electric reads, must be understood in order to ensure adequate capacity is available to handle the increased billing and customer data presentment requirements.

Enhanced Services - Ancillary Devices to Support Customer Compliance with CPP and TDP

1. Other methods of Customer Notification and Information

More consumer friendly devices exist that can assist the customer in understanding their usage and providing feedback regarding their success in mitigating usage during Critical Peak Periods.

Notification to the customer of pricing changes can be provided through a paged signal to a:

- Smart Thermostat with a two or three line LCD message display
- A series of lights: red, green and yellow that when lit would signal what energy period is in effect

Information through a wired or remote connection to the meter can offer real time usage data to the consumer. Devices on the market include:

- Remote RF signal of updated usage information to a Smart Thermostat with two or three line LCD message display of meter reads in kW and in dollars spent
- Wired connection to a read device clamped to the meter that provides the usage in to the customer in kW and in dollars spent

These devices offered by the LDC subsidiary or Retail Company as an enhanced product service for a monthly fee or can be purchased outright by the consumer.

2. Load Control – by LDC or Alternate Service Provider

Load Control/Management systems can be installed to assist the customer in curtailment/shifting compliance:

a.) Paged or broadcast message to smart thermostat that automatically adjusts the temperature setting up or down by about 2 degrees

b.) Internet message and bulletins of critical peaks that advice the consumer to curtail load.

c.) Broadcast signal (generally using and public RF or licensed band) to load control devices installed on high energy devices in the home. Customers sign up for these programs and opt for an automated option to effect scheduled cycling or direct cuts in loads to specific appliances connected to receivers on:

- air conditioning
- thermostat adjustments of 2 degree increases or decreases
- water heater load
- pool pumps, etc.

Appendix D-4: Potential Price Structures Critical Peak Pricing (CPP)

Notification of a Critical Peak (CP) will be provided 24 hours prior to the time the event will be instituted.

Critical peaks will begin on the hour. It is anticipated that 2003 is a representative year for the type of Critical Peaks that will occur on any given year in the Province of Ontario.

Critical Peak Periods have been determined to be representative of the following history. However, it is expected that these peaks are historical representation and may change over time and vary by day.

CPP Periods

Table 6

Market Clearing Price	2002		2003		2004	
	hrs.	**days**	**hrs.**	**days**	**hrs.**	**days**
$100/MWh	272	67	611	112	227	52
$150/MWh	115	33	198	54	17	10
$200/MWh	62	19	50	15	4	4
Data Source	5880	245	8760	366	5856	244
Mean - $/MWh	51.998		54.042		49.709	
Min - $/MWh	7.84		11.54		5.25	
Max - $/MWh	1028.42		548.52		340.45	

Based on the information provided above and using 2003 as a typical year, the Data and Communication Working Group determined if there would be any risks to the consumer when reconfiguring the TOU/CPP schedule. It was noted that with 16, 54 or 113 CPP days, the LDC may be required to reconfigure the TOU/CPP schedule 32, 108 or 226 times per year (assuming worst case scenarios). Limitations of the SMS must be carefully considered for either an interval data collection or TOU SMS. Performance specifications must be developed in the RFP to ensure functionality requirements can be met regardless of the SMS selected.

Time of Use Pricing (TOU)

The ability to offer TDP reads must be present at the meter level or through the acquisition of hourly time stamped reads that can be collected and then transmitted to the Smart Meter Data Collection Computer (SMDCC). Reads collected must be deposited into the appropriate rate segments. Read time period segments must be updated daily as new reads are acquired and deposited into the Smart Meter Data Collection Computer (SMDCC)

TOU Schedule

TOU capability must be able to comply with a minimum requirement for provisioning for 3 different rate periods allowing for three off rate days to comply with holidays and weekends. Seasonal changes must be possible without reprogramming at the meter.

Timing Reference of the SMS

Time reference in the SMS must be synchronized using an approved time synchronization process and a recognized time standard setting atomic clock that maintains time to 1 second to match time used by the IMO. The SMS is operated and synchronized to Eastern Standard Time.

See Appendix B for analysis of timing requirements and cost implications associated with drift.

Accuracy of Time Reference

Time synchronization must be completed on a regular basis to assure accuracy never exceeds +- 5 minutes. Synchronization must be maintained and be able to prove time accuracy falls with in the timing tolerances. A daily status reporting process must confirm time tolerance levels are in compliance in accordance with the reads acquired within the previous 24 hour time period.

Daylight Savings Time (DST) Data Collection Requirements

SMS must be able to handle 25 hours of interval or TOU data based on local DST switch dates twice per year.

Appendix D-5: Time

Timing Reference of the SMS

Time reference in the SMS must be synchronized using an approved time synchronization process and a recognized time standard setting atomic clock that maintains time to 1 second to match time used by the IMO. The SMS is operated and synchronized to Eastern Standard Time.

See Appendix B for analysis of timing requirements and cost implications associated with drift.

Accuracy of Time Reference

Time synchronization must be completed on a regular basis to assure accuracy never exceeds +- 5 minutes. Synchronization must be maintained and be able to prove time accuracy falls with in the timing tolerances. A daily status reporting process must confirm time tolerance levels are in compliance in accordance with the reads acquired within the previous 24 hour time period.

Customer Notification of CPP

Customer notification and data presentment must be provided to customers in local DST.

Daylight Savings Time (DST) Data Collection Requirements

SMS must be able to handle 25 hours of interval or TOU data based on local DST switch dates twice per year.

Basic – Pricing Signals and Changes

Assumption: Pricing changes from flat rate or standard TDP will be provided with a minimum of 24 hours advance notice. This type of ad hoc pricing is referred to as Critical Peak Pricing

Timing of Price Changes

Pricing changes will take place on the hour.

Reconfiguration of Time and Read Buckets for CPP

Changes to CPP and TOU Rate schedules must be processed through system configuration which must be completed within 16 hours of notification

Performance Requirements for Pricing Reconfiguration

Reconfiguration of all Smart Meters operating in the field should be 95%. Programming for confirming initial reconfiguration and modifying/compensating for non performance of the communications signal must include the means for retrieving reads in TOU buckets and allocating them through software to the appropriate CPP time periods.

Customer Notification of Pricing Changes

Customer Notification will take place via Public Media – Newspaper and Radio, TV. Notification process must begin immediately following LDC receipt of CPP or TDP pricing changes.

Notification must also take place with bulletins issued via emailed links to web page bulletins notifying customers of an impending CPP.

LDCs are required to obtain and maintain customers' email addresses in their CIS.

Appendix D-6: Basis for Smart Metering System Request for Proposal

SMCM Physical Characteristics

1. **Meter Socket Interface**

   SMCM and/or meter to be used for the Smart Meter initiative must be able to connect to existing LDC meter sockets.

2. **Electrical Isolation**

   SM device must be protected and demonstrated to withstand from electrical transients, surges and harmonics originating from the electrical service. Every SM device must meet ANSI standards.

3. **Labeling**

   The SM device shall be permanently labeled with:
   - Manufacturer's name
   - Model number
   - Identification Number
   - Required DOC and CSA labeling
   - Input/output connections
   - Date of manufacture

4. **Physical Labeling of the SM Communication Module**

   Barcoding of SMCM label must be provided if requested by the LDC.

5. **Reconfiguration of SMCM to Accommodate New Pricing Changes**

   SMS must reconfigure to accommodate new pricing changes/modifications 16 hours after notification of a rate change. SMDCC reporting must confirm that the reconfiguration change was successful.

Communications and SMRC

Smart Meter LAN/WAN Network Requirements

a. Transmission of Usage Data

The daily read period for transmitting customer usage information is from 12:00 midnight to 12:00 midnight of each day. Data can be transmitted more frequently during this time period if required by the system or for provision of enhanced services.

Meters can be read and data stored at any point between the meter to the SMDCC. Transmission to the head end or SMDCC must take place at a minimum every 24 hours between 12:01am – 5:00 am.

b. Transmission Requirements

Base level requirement:

LDC's have the interim option of collecting and transmitting TDP data instead of hourly interval data if it can be proven after the four-month initial collection period that customers are satisfied with the data information they are receiving. However the capability to collect hourly interval must be present in the SMCM.

While not all customers are expected to require nor want hourly interval data on a daily basis the network topology must be configured to hold the resident capacity to acquire hourly interval reads from all SMCM deployed in the LDC service territory.

c. Smart Meter Regional Collectors (SMRC)

The SMRC acts as an intermediary data collection repository for meter data coming from the SMCM. If no memory or very little memory exists in the SMCM the SMRC may act as the memory and storage point for the data as well as for the date and time stamping of the data. The SMRC is the SMS bridge between the LAN to the SMCM and WAN to the Smart Meter Data Collection Computer. Ability to interface to variable telecommunications media options (private or public) such as fiber, telephone, radio frequency may vary by vendor SMS.

1.3.1 SMRC Transmission Range

Location and structures specific to the optimal placement of SMRC must be provided by SM vendors using verifiable information regarding the expected transmission range between the SMCM and the SMRC. Provision for powering of the SMRC must be present regardless of the location and structure required for placement of the SMRC.

If licensed frequencies are used from the SMCM to the SMRC then wattage output frequency allocation must conform to DOC requirements and average transmission ranges must be noted.

Vendors must offer preliminary propagation surveys of the LDC service territory in order to provide a configuration topology regarding the number and location of the SMRCs. A topology outlining minimum and maximum number of SMRCs and transmission range must also be provided to the LDC.

A listing of considerations of known structures, circumstances and other issues contributing to RF anomalies must be provided by the SM Vendor with the topology maps and SMRC configuration analysis.

Cost implications for maximum and minimum throughput based on transmission ranges must also be provided by the SM vendor.

1.3.2 Conformance with DOC Radio Spectrum

Radio Frequency allocated to the SMRC must be DOC approved and available for use over the lifetime of the system by the LDC. SM Vendors are responsible for acquiring the necessary radio frequency from the DOC on behalf of the LDC. LDCs may offer their assistance in help to secure the frequency or in testing their service area to make sure unused frequency spectrum is indeed vacant and able to be utilized by the SMS.

Spectrum allocation and wattage of the signal must not impede neighbouring frequencies while still delivering on the expected transmission range requirements for the necessary SMRC topology configuration.

1.3.3 Interface to Multiple Media WAN Options

SMRC must provide a minimum of one connection to either a public or private WAN communication media link that will transmit data back to the SMDCC. Alternative network WAN options can include one or more derivatives of the following but must not adversely impact consistency of acquiring 95% read retrieval success over a three-day period.

- Private RF Options – Microwave, mobile bands, SCADA, etc.
- Public RF Options- digital cellular, paging, PCS, etc.
- Wireline – Telephone, Dial-up, dedicated/leased lines, etc.
- Fiber – Ethernet, Frame Relay, etc.

1.3.4 Deployment Characteristics

Form factors of the unit, powering requirements, and location on structures such as light pole standards must be provided outlining weight and height specifications as well as optimal location for installing the SMRC.

d. Loss of Power/Functionality at the SMRC

No power at the SMRC constitutes a high priority status issue on the network and SM Vendors must state how SM Operator is alerted to a failure and how risk of lost data is mitigated.

e. Communication Link Failure

Communication link failure that impact the 95% read retrieval requirement is classed as a high priority status issue on the network and the SMDCC must be notified of the impending impact in order to take action to correct this failure and protect the read retrieval process.

f. Time & Data Storage Memory

SMRC must be time synchronized with the SMDCC. Meter read storage must be configured to accommodate redundancy requirements and ability to maintain read acquisition levels at the SMDCC at better than 95%.

Data storage and the base level for collecting hourly interval data from all meters deployed in the system must be configured into the SMS deployed by any LDC.

1.6.1 Addition of Water or Gas Meters on the SMS

If water/gas meters are to be included in the SMS deployment then these additional SMCMs must be included in the complete SMS topology at the time of the network configuration including necessary provisioning for memory, as well as bandwidth requirements to meet data transmission timelines on the WAN..

g. Redundancy

Network configuration must take redundancy levels into consideration along with interface requirements such and bandwidth, through put and costs for provisioning for this redundancy, transmission timelines as well as the requirement for 95% read transmission success rate.

Automated programming either at the SMRC or at the SMDCC must sort reads and compare and eliminate duplicate reads prior to E&R processing, data archiving as well as web presentment to the customer.

Management, Warehousing and Processing for Billing

1. Smart Meter Data Collection Computer (SMDCC)

Usage data collected from the SMCM and transmitted over the network is retrieved and stored in the SMDCC. Depending on the level of sophistication housed in the Smart Meter System the SMDCC will issue operation/status reports following the download of data every 24 hours. The SMDCC is the central point for entering new SMCM and connecting this database to the LDC customer database. It is the central control point for all adds, moves, changes and SMS status indicators for maintaining the healthy operation of the SMS.

2. Monitoring and Measuring 5% Demand Reduction

In order for the province to recognize that the 5% demand reduction has been achieved, it is necessary to implement the Smart Meter System and acquire a representative sample of customer usage profile information prior to the implementation of the rates and programs that are being built to support.

3. Replacing Missed Reads

Note: WGD&C recommends a provincial standardized estimating and rebuilding of data (E&R) be development and implemented in order to ensure consistency in the format and handling of all missed reads and the resulting manner in which bills are prepared and offered to the customer.

4. Data Storage in the SMDCC

The SMDCC must have the ability to collect and store all 24 hourly interval reads from each SMCM deployed, even if only TDP read segments are being collected and transmitted.

A minimum of 40 days of read storage must be present in the SMDCC in order to process reports regarding trending of SMS operations regarding SMCM and SMRC functionality and WAN status.

5. Configuration of New Rate Changes

The SMDCC must be able to send a message to one, any or all SMCM/SMRC in the field. The ability must be present to broadcast rate changes, reprogram groups of SMCM and confirm that changes in read collection intervals has been successfully completed.

6. Calculating Demand

Regulation for all SMCM connected to commercial three phase meters requiring a demand reading is to acquire the read from the meter. If this functionality is not available at the meter level then the SMDCC must be capable of collecting the hourly interval reads and provision for either sending this information to the complex billing software to calculate demand or offer the ability within the SMDCC to process the demand read every 30 days and send it to the data repository or LDC CIS.

Regulations must be consulted to determine if demand can be collected and stored in the SMRC.

1. Monitoring of the SMS and Reporting Capability

Full Disclosure in Relation to Province of Ontario Smart Meter Specifications:

Vendor must include in SMS specification the number of transmissions required daily in order to achieve base requirements. Vendor must indicate memory capacity and how data redundancy and integrity are maintained.

Non-Critical SMS Reporting

The system shall be self-monitoring and provide status reporting to the SMSDC on the following operations:

- Successful initialization of SMCM installed in the field
- Discrepancies in SMCM and CIS links

Successful capture of readings – benchmark of the 95%

- Read reports
- Alarms and status indicators at SMCM
- Suspected tamper and trending reports

Unsuccessful capture of readings – benchmark of less than 5 %
SM communication link functionality monitoring,

- SMRC – Status Indicators

Critical Transmission Reports

Critical reports are any operational issues that impact the successful achievement of receiving 95% of all read intervals transmitted

- Network Failures
- Communication Link Failures
- Power Failures
- Memory Capacity Issues
- Meter Failure
- Critical Peak Pricing – problem with verification of reconfiguration of time buckets of SMS using TOU pricing and usage retrieval

Remote Programming and Upgrading of SMCM Device Functionality

SMDCC must have the ability to broadcast to all or specific groupings of SMCMs, rate program changes, adjustments etc on a system wide basis or by specific customer programs or locations.

Scalability

Performance parameters specified for the SMS must meet the Smart Meter Functional Spec and conform to this level of functionality regardless of whether the system is operating based on an initial deployment configuration or has migrated to include the majority of the utility's meters in the specified service territory.

SMS functionality refers to the capability of meeting read and interval requirements and data transmission throughput as specified in the RFP and the SMS Functionality Specification

Manageability

As the SMS increases in number of end points, the ability to manage the data retrieval process and maintain the necessary reporting capabilities must still be maintained to initially approved performance specifications.

Interconnectivity

Ability to Interface to Multiple Vendor SMS solutions

While not a requirement, the Province of Ontario endeavours to promote the ability of interconnection between various vendors' SMS. The ability to integrate more than one system to provide a hybrid solution that promotes an open bidding process between a number of vendors communication modules and utilizing only one head end would be the vision toward which all Vendors should be directing their product evolution.

Communication to Multiple Media Options

Ideally the SMS systems should be configured by 2007 to be able to interface to more than one communication medium. This type of enhancement will promote the ability of the utility to extend the initial network deployment and provide a level of flexibility to enable the optimal transmission of data depending on prevalence and cost to use one media option over another.

Appendix D-7: Editing and Rebuilding of Data

Estimates of consumption will be required from time to time when true meter readings are not available. This may occur after malfunction of the meter or the data system. Meter malfunctions are usually permanent requiring replacement of the meter. Communications malfunctions are often temporary usually causing data to be late rather than lost.

Data shall be validated before being passed to the settlement system. Suspect data will be adjusted using the procedures described below. The validation criteria required depends the technology used to meter and collect readings. The validation to be applied will be defined by the distributor.

When valid data is unavailable at the time of billing it shall be adjusted using uniform estimating rules approved by the OEB. This appendix provides an outline of the proposed estimating and recalculation process.

Guiding Principles

In the retail market, meters and data collection systems will be owned by the distributor, or the distributor's delegate. The distributor is responsible for ensuring correct and reliable meter readings.

When meter data is adjusted during the estimating process, there is always some risk that the estimated value will differ from actual consumption. Every effort must be made to ensure each estimate reflects accrual consumption to the extent possible. And to the extent possible, the risk of error should be born by the distributor.

This guideline applies to active, reactive and apparent energy.

Definitions

Cumulative energy register means a device, which indicates cumulative energy consumption. The indication never decreases except when the register "rolls over" to zero and starts again. Energy consumption over a period of time is calculated by subtracting the reading at the end of the period from the reading at the beginning of the period.

Interval energy register means a device, which indicates the energy, consumed in a particular period of time usually 15 or 60 minutes. The reading is time stamped to indicate the date and time at the end of the interval. Energy consumption over a period of time is calculated by summing the interval energy values over the period to the end.

Raw data means data as collected from the meter which has not been adjusted and which may contain missing or invalid readings.

Presentment data means meter readings collected from the meter and available to the consumer within 24 hours of the consumption day. This data may or may not be the final data to be used for billing.

Billing data means valid or rebuilt readings used for billing.

Billing period means the period of consumption for which the consumer is invoiced, typically 1, 2 or 3 months.

Estimated consumption means energy consumption estimated by selecting the minimum consumption in three previous comparable periods equal in duration to the period of missing or suspect data. If three comparable periods are not available, the estimated consumption would be based on the minimum of the previous two comparable periods. If two comparable periods are not available the estimated consumption would be zero.

Proposed Editing and Rebuilding Methodology

Cumulative Consumption Meters

Meters fitted with cumulative energy registers can be read once per day or every hour to obtain the time stamped readings from the cumulative energy registers. The consumption in each day is calculated by taking the difference between the register reading today and the register reading yesterday. Meters are typically fitted with three such registers one for critical peak pricing and three more for a three tier time of use rate.

Estimating for Presentment

In the event that either reading is missing, the daily consumption may be estimated as either the:

1. consumption the day before; or,
2. estimated consumption

Recalculation & Rebuilding for Billing:

Contiguous daily consumption readings are not required for normal billing. When readings at the beginning and end of the billing period are available the consumption is calculated by taking the difference between the current and previous readings. All readings in between are for information only.

End Reading: Should a reading for the end of period be unavailable, the first valid reading (hourly or daily) prior to the billing date shall be used as the end of period reading. Billing for the next period would resume at the new end of period.

The result of this calculation need not be marked as estimated since it is based on true metering readings.

Begin Reading: Should a reading for the beginning of period be unavailable, the first valid reading (hourly or daily) after the beginning of period shall be used as the beginning of period reading. The consumption between the end of the previous period and the beginning of the current period replaced with estimated consumption. Missing and suspect begin readings should be infrequent since the begin reading is the same as the valid end reading used in the previous billing period.

The result of the calculation must be marked as estimated.

Interval Consumption Meters and Hourly Profile Systems

The smart meter system may produce hourly profile data by:

1. reading time stamped interval registers within the meter; or,
2. reading a cumulative energy register followed with time stamping in a regional collector intermediate between the meter and the billing system

Estimating for Presentment

The consumption in each hour may be estimated as either the:

1. consumption in the previous hour; or,
2. *estimated consumption.*

Estimating and Recalculation for Billing

Meters with on-board interval registers may record consumption in 5, 15 minute or 60 minute intervals.

Hour or Less: For durations of one hour or less, linear interpolation may be used to estimate consumption in contiguous 5 or 15 minute intervals.

Over an Hour: For durations exceeding one hour, estimated consumption shall be used for each hour comprising duration of missing or suspect data.

The result of the calculation must be marked as estimated.

True Up: If other registers in the meter provide valid cumulative energy readings any time before and after a contiguous group of estimated hours, the true amount of energy consumed over that period will be known. The consumption in each hour previously estimated would then be scaled by a factor that would make the consumption represented by the sum all hours in the period equal to the difference of the cumulative energy register readings for the same period.

If the meter is fitted with time of use registers and critical peak registers, in lieu of a single cumulative energy register, these may be used to calculate the cumulative energy used for true up.

The result of the scaling calculation need not be marked as estimated because true energy consumption is known.

Appendix D-8: Customer Information

1.1 Data Presentment to the Customer

The previous day's usage information must be available for access by the customer by 8:00 am the following day. At this point this data may be portrayed as unscrubbed data. Scrubbed data must replace initial data within three days. Unscrubbed data should be clearly recognized and noted on any data presentment medium. Information must be presented in a format reflecting the method, time and rate structure in relation to what is being offered and used by the customer.

1.1.1 Customer Notification of CPP

Customer notification and data presentment must be provided to customers in local DST.

1.2 Amount of Data On-line

1.2.1 Upon Initialization/Start-up

For the first four months following the Smart Meter System installation, LDC must collect hourly interval reads and present the information to this level of resolution in order that the customer can understand their consumption at any time period throughout the day. The LDC must also provide the information as per the example to enable customers to see graphically how their usage equates to the TDP rate structure that they are using. Customers will have access to this data for the first four months following the installation of their SMS.

1.2.2 Detailed Meter Reads and/or Usage Data On Request

Interval or Time Of Use Data may be presented on an on-going basis if the customer specifically requests this level of data presentation.

Depending on interest level and preference this information may be condensed to show only TDP graphs with summary daily reads with updates every 24 hours after the first four months. Customers can request that hourly interval data collection and presentment be maintained following the four months. Level of interest and request will have a marked impact on the SMS network configuration, WAN and data collection and warehousing costs associated with operating the SMS.

1.3 Data Updates

In all cases, summary data will be updated on a daily basis either with the complete number of meter reads or the summarized information in the appropriate rate structure being used by the customer during the first four months of operation.

Customers' monthly billing history will be presented on-line and summarized and updated monthly.

For comparison purposes 13 months of on-line data must be available to the customer in order to fulfill conservation and demand management comparison requirements

Format: First year (following installation) hourly data for first 4 months followed by usage data as per the rate structure subscribed to. Daily updates will be accessible on-line for 13 months, showing summary daily reads, based on subscribed rate structure . See example

1.3.1 Data Updates to the Customer

Data updates should be made every 24 hours and be available to the customer via the web or by calling in to an IVR or CSR by 8:00am each day following the last read transmission of the previous day.

1.4 Data Availability

1.4.1 Downloading Customer Data

The web and on-line access must provide the ability for downloading by the customer to archive and self manage if so desired.

Appendix D-9: Options for Presenting Data to the Customer

Based on the varying levels of technology available to the customers, LDCs could provide information to customers using the following methods:

- Internet
- Email messages to access secure personal Web Site
- Automated Voice Response and/or Customer Service Support Line

Internet

While the majority of the customer base may not have access to the internet, this method was deemed to be the most cost effective for reaching many of the LDC's customers. Customers with internet connectivity could access their individual, password protected, Smart Meter Web site to collect and view their archived summary energy data or their previous days' usage information—if they are within the first four months of their SM installation. Information should be downloadable by the customer.

Email

An additional option or in conjunction with the protected web site is to email the link to the customer each day. At the same time, notification of upcoming CPP can be sent along with energy saving tips and options for reducing demand during peak periods.

Automated Voice Response (AVR)

LDCs have the option of AVR, touch-tone driven menu system, or using a customer service representative (see next item)

Non-electronic method for providing information to customers must centre primarily upon the telephone as the most universal and easy to use means for disseminating information that is less than 24 hours old. Customers can access their information through special toll free lines that require an access code to enter the Automated Voice Response system. A verbal summary of the information from the previous day's usage as well as a summary comparison of usage between the current and previous month can be accessed with touch-tone menus.

Options and information can be presented in similar formats to those practiced by cellular phone companies.

Various levels of information based on energy used and/or dollars spent during specific time periods would include such topics as

- Regular Time of Use rate program information
    - Difference in the cost of consumption from the previous day,
- Cost for usage in current month
- Comparison of cost to the previous month, etc.

Customer Service Representative (CSR)

Designated CSRs can also be used to provide information to customers that do not or cannot use the AVR menu driven telephone information system. Access to this personal service may be completed by calling the same toll free number and waiting on the line or pressing “0” to reach a CSR.

CSRs could have access to web presentment information as well as basic summary data for quick responses to customer queries.

Appendix D-10: Outsourcing/Partnering/Service Bureaus

Ownership and Operation of the SMS

LDCs must have the option of owning the communication module and/or communication infrastructure but have the ability to outsource the data collection and warehousing to a third party.

Business agreements to provide SMS to LDCs may entail any or all of the following ownership options:

- lease
- share
- own

LDCs may initially own and operate the SMS but may develop requirements to outsource various functions of the overall management of the SMS.

Service Bureau Operation Opportunities

Service Bureau or Third Parties can provide the following SMS services for the LDC:

- Install smart meters and SMCM
- Collect meter data and forward to the LDC for billing purposes
- Process SM data for billing
- Provide automated E&R of missed meter data
- Store and Archive Data online and off-line
- Relay required usage information to Retailer and Customer
- Web Presentment Capabilities
- Automated Voice Response service for responding to Customers on behalf of the LDC

Appendix D-11: Technology Guidelines for SMS

SMS Functionality Performance Guidelines Based on Technology Topology

The inherent strengths and weakness of each SMS is inherently based to a large degree on the telecommunications medium used to transmit the data. Diversity in the type of customer base, demographics and telecommunications infrastructure availability will necessitate LDCs selecting systems that are most appropriate, cost effective and available for deployment in their service territory. Apart from telecommunications infrastructure availability, the distance between meters is often a key factor in SMS selection as it will determine system performance and ultimately the overall cost per point of entire SMS. The following information is a guideline that offers some insights into the various options taking meter proximity and telecommunications infrastructure availability, into consideration.

Reader Note: It must be noted that this section is a SMS guideline and exceptions do exist as specific SMS vendors may have overcome some obstacles noted in this section as impediments to achieving required functionality. These exceptions may enable certain SMS to provide the necessary functionality to comply with the minimum requirement.

1.1 Geographic Segmentation of Residential and Commercial Customers up to 50 kW – no demand

For the purposes of describing SMS technologies in this specification, WGD&C has formulated an analysis of the most prevalent technology options for three basic customer types based only on geographical conditions. This section serves as a guideline in assisting LDCs to select the type of SMS that will best address transmission issues and communications media availability. These customer segments are as follows:

Rural – Majority of LDCs customers' meters are more than 1000 ft apart. Represents smaller northern utility service territories or Hydro One remote customers.

Suburban – Majority of LDC customers meters are dispersed with the largest percentage being less than 1000 ft. apart (Areas generally match those where cable TV and natural gas is available)

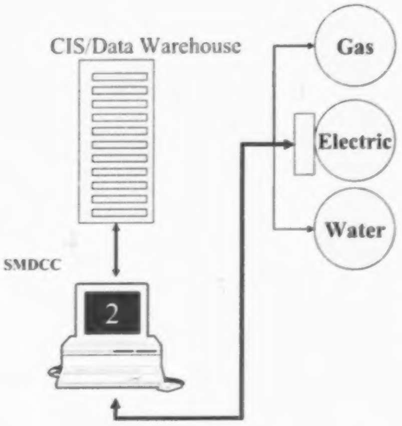
Urban – Majority of LDC customer meters are in close proximity of less than 500 ft. Utility is referred to as a city with high density population.

Table 7

LDC Predominant Customer Type	Average Meter Distance	SMS Options	WAN Options
Rural	Over 1,000 ft.	Powerline Carrier (PLC) Telephone (shared line) Possible rural RF	Fiber Microwave Telephone – dedicated/dial up
Suburban	500 ft	Private RF networks Public RF networks Unlicensed RF networks PLC Telephone (shared line)	Fiber Public RF networks Licensed RF Telephone dedicate/dial-up
Urban	<500 ft	Private RF networks Public RF networks Unlicensed RF PLC Telephone (shared line)	Fiber Public RF networks Licensed RF Telephone dedicate/dial-up

1.1.1 Telephone

Inbound Telephone SMS



1. The SMCM device calls the utility control computer at a prescheduled time.
2. The control computer acknowledges the device and acquires the read.
3. The control computer acquires the meter information and then updates the call schedule, etc, in the SMCM device.
4. The information is collected in the SMDCC and is batched regularly or on command to the CIS/MIS/Data Warehouse

Figure 3

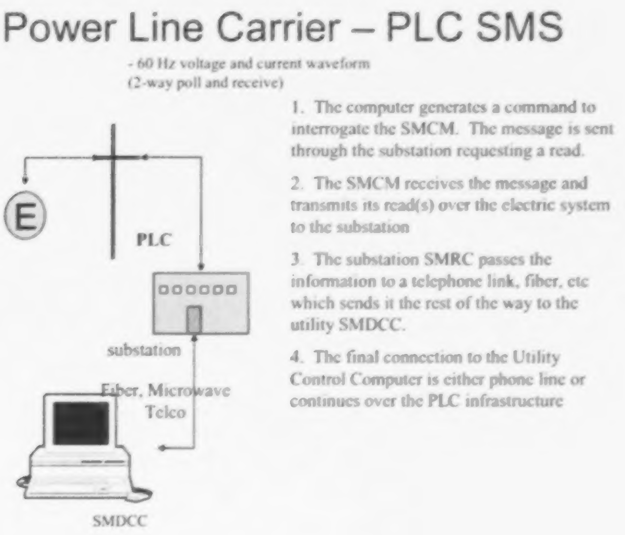
An SMS connected to and sharing the customer's residential telephone line must not override or impede the primary use of the telephone for the customer's primary requirements. The SMS must release the line if it is in use and restore dial tone to the customer in the event the telephone is accessed.

Call schedules for downloading reads would be programmable and transmit at a time when the customer is least likely to access the phone line for personal use.

The customer must give permission to the LDC to use their telephone line for SMS connection

A real time clock or method for synchronizing the time in the meter for read accuracy must ensure the elimination of drift beyond the tolerance level of +-5 minutes in the internal clock. Reads must be time stamped.

1.1.2 Powerline Carrier System (PLC)



Power Line Carrier – PLC SMS

- 60 Hz voltage and current waveform
(2-way poll and receive)

1. The computer generates a command to interrogate the SMCM. The message is sent through the substation requesting a read.
2. The SMCM receives the message and transmits its read(s) over the electric system to the substation
3. The substation SMRC passes the information to a telephone link, fiber, etc which sends it the rest of the way to the utility SMDCC.
4. The final connection to the Utility Control Computer is either phone line or continues over the PLC infrastructure

Figure 4

PLC SMS have a distinct advantage of being able to provide smart meter functionality to every electric meter within the province of Ontario.

1.1.3 Wireless Networks

SMS utilize an number of wireless network options form common public unlicensed bands in the 900 to 928 MHz range to high powered licensed frequency to achieve a broader transmission and retrieval range. Each option comes with a set of advantages and disadvantages that during the selection process are weighed to determine maximum throughput and capability based on topology each LDC has the ability to implement.

1.1.4 Private Licensed Frequencies

SMS systems built for North America using licensed frequencies may or may not be able to operate in Canada. For utilities to be guaranteed that the system will function, and at the cost quoted by the SMS vendor, accountability for frequency allocation and associated infrastructure for collectors are the responsibility of the vendor. Vendors will conduct propagation studies and determine network configuration, costs and ratio and potential for interference of the transmission signal. Vendor will acquire the license on behalf of the utility and modify requirements and technology to meet the Canadian regulatory environment.

Duration of the radio licenses must be available for use over the cost and product lifespan of the SMS.

1.1.5 Public RF Networks – SMRC – SMDCC (WAN applications Only)

1.1.6 Public RF Networks – SMCM to SMDCC (WAN applications with no LAN)

Publicly owned wireless networks with the primary service offering being either public voice or data services do not depend on SMS for its primary source of revenue. Service providers are responsible for maintaining and upgrading the network. This alleviates core responsibility and the maintaining of staff with specialized skill sets within the LDC.

SMSs using this transmission option are more appropriate to commercial and industrial customers. Modem costs, network rates and overall SMS deployments can be easily deployed in a dispersed method rather than the more traditional cost contained cluster type deployments for residential SMS.

Each SMCM can be implemented on a one of basis with the capacity to transmit as much or as little data as required (EG: TDP rates and hourly or even 15 minute or smaller intervals). Data transmission is billed based on usage and SMS vendors are increasingly building in data compression techniques that strip out redundant bits, headers, addressing, etc. in order to compress 1 MB data streams into several kilobyte packets.

LDC's should evaluate SMS vendor ability to compress data. For full cost determination the on-going data transmission costs must figure into the viability of using this option.

Depending on LDC location can determine the availability and type of wireless public networks that can be used. Options range from analogue cellular systems to the newly implemented GSM options. The SMCM can be the meter glass or in an adjunct box. Each option must be considered for longevity of the RF option and ability to upgrade the device over time if the public network service provider changes the system.

SMS vendors in this category must have access to the three phase meter protocols to the level with which the LDC will require data to be transmitted. (beyond a single channel of data). Base level of service by most vendors is a single channel of data with demand read inside the meter and remote demand reset.

Recommendation: WGD&C recommends that a bulk purchasing agreement be implemented for utilities opting for this network solution in order to strike the most cost effective pricing contract with the wireless network provider.

1.1.7 Unlicensed Frequencies

Spread spectrum is the public open band for radio frequency transmissions requiring no private license or ongoing fees. Vendor propagation studies are encouraged to determine the level of data traffic currently running at this frequency in a utilities' service territory to ensure that data collisions and/or congestion in this band will not impede the required SMS throughput.

Unlicensed frequencies are predominant in mesh network options where frequency hopping and repeater transmissions enable the network to expand (with some systems) up to 5 miles in radius even when actual transmission distance between meters is less than 500 ft.

Low density rural and sparsely populated suburban may not have the infrastructure necessary to promote the use of this technology

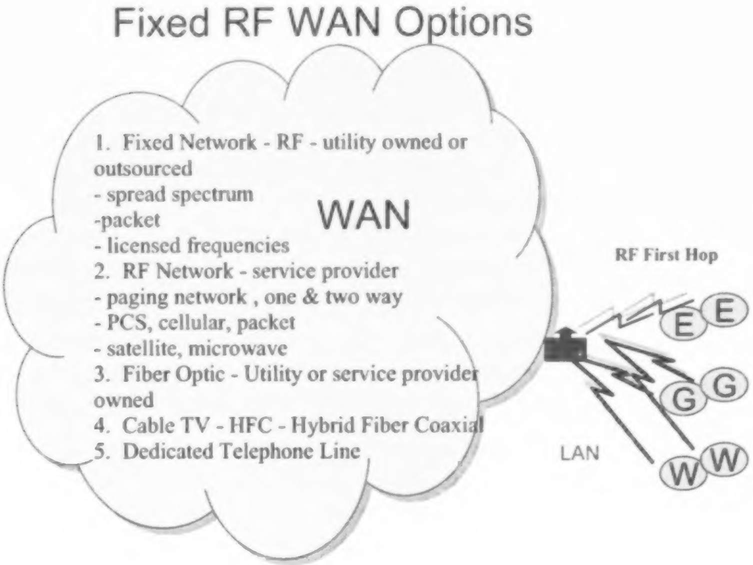
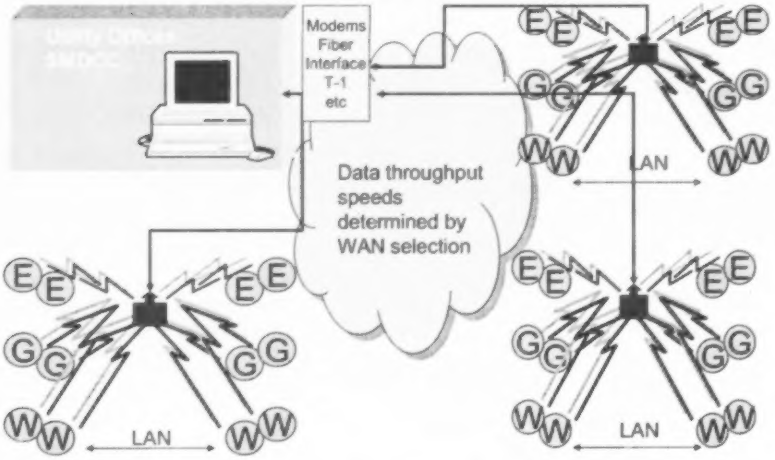

Fixed RF WAN Options
1. Fixed Network - RF - utility owned or outsourced
- spread spectrum
-packet
- licensed frequencies
2. RF Network - service provider
- paging network , one & two way
- PCS, cellular, packet
- satellite, microwave
3. Fiber Optic - Utility or service provider owned
4. Cable TV - HFC - Hybrid Fiber Coaxial
5. Dedicated Telephone Line
WAN
RF First Hop
E
E
G
G
W
W
LAN

Figure 5


Radio Frequency Fixed Network SMS

LAN Distance depends on whether frequency is licensed or unlicensed and power used to transmit the read

Figure 6

1.2 Rural Considerations Necessary to Ensure SMS Compliance

1.2.1 Hourly Interval Data

Lack of multiple infrastructure options provides unique challenges to the rural utility. Provision for the collection of hourly data must be available and vendors must state how this will be achieved from all meters deployed in the system.

1.2.2 Time of Use

Time of Use with no ability to reconfigure the time collection periods and with no capability to acquire hourly interval reads will not meet the province's SM requirements.

1.2.3 Regional Data Collectors

Usage Data may be collected and transmitted to an interim data collector that may be located at the substation. Access and use of existing infrastructure such as microwave, fiber and dedicated telephone lines, etc. to back haul the data to the utility, can be used if the interface exists and is provided by the SMS vendor.

1.2.4 Data Collection:

To minimize costs the SMS for small regional rural utilities must have the ability to service multiple small entities through one head end. Data collection and sharing can be facilitated for a number of small entities through purchase of a high-speed link to a centralized data collection and warehousing facilities. Data from multiple utilities should be protected and firewalled to maintain custodial responsibilities of the LDC and privacy of individual customers.

1.3 Communication Options From The Meter to SMRC (LAN) or Utility SMSDC (WAN)

Table 8

Excellent - ●, Good - □, Fair □, Undetermined in Canada - □, Poor - □			
Medium	Rural	Suburban	Urban
PLC	□[13]	□	□
Telephone	● Must ensure connectivity to line exists	●Must ensure connectivity to line exists	●Must ensure connectivity to line exists
RF 200 MHz	□ - US option for rural Not available in Can	□ - Possible if frequency is available for use	□ - Possible if LDC wants to build the network
RF 400 MHz	□ Not cost effective in sparse population	□● - Frequency must be secured but still need WAN to get data to head end	□● - Frequency must be secured, no interference, infra for WAN still req.
RF 1.4 GHz	□Not applicable for rural	□● - Still in R&D and must ensure does not run contrary to other allocations	□● - An option if proven and does not run contrary to other RF allocations
SS – 900 – 928 MHz	□Public band may not be able to travel beyond 500 ft	● - May be an option if population is within the 500 – 700 ft. radius. Topology dependent on geographic meter density	● - will require propagation study to determine level of activity from other users

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[13] Ensure interval data can be collected from all meters every day at each substation

1.4 Communication Options From SMRC/Substation to Utility SMDCC (WAN)

Table 9

Medium	**Rural**	**Suburban**	**Urban**
Dial-up Phone Line[14]	Interface to PLC at substation	Interface to RF collectors	Interface to RF collectors
Dedicated Phone Lines	Interface to PLC at Substation	Interface to RF collectors and PLC	Interface to RF collectors and PLC
Microwave	Interface to PLC at the Substation	Not frequently used to interface to RF collectors	Not frequently used. Interface may not be available by SMS RF Vendors
Fiber	Interface to PLC at substation in form of Frame Relay, Ethernet, T1, etc.	Interfaces to RF collectors 400 MHz and SS 900 master data collection meter	Interfaces to RF collectors where fiber termination points exist. Uses existing utility infrastructure
Public Wireless Analogue Cellular	Analogue Cellular Can act as a good back haul in rural as little traffic on system	May be an option depending on location	Is being phased out and an economic risk to invest in interfaces using this technology
Public Wireless Digital Voice/GSM	Not readily available throughout rural Canada	Interfaces to collectors 400 MHz	Low cost option for downloads nightly on evening rate with data transmission cap

1.5 Customers Between 50 to 200 kW

LDC customers in this market segment will require hourly interval reads as well as a demand read. SMS options are more complex than those listed for residential customers and LDCs must consider if the residential SMS will be robust enough to address data collection and billing requirements for this level of customer.

At the same time, connection of these customers to the traditional MV-90 data collection option are often deemed too expensive and could quite possibly put too much pressure and impact performance of the MV-90 platform.

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[14] Suitable for small numbers of meters downloading interval data. Use other options for increasing through-put and concentrating the number of ports required at the SMDCC.

SMS options for 50 – 200kW customers must ensure that all requirements stated in the SMS functional specification for single-phase residential customers are met along with the ability to read demand.

Table 10

Media Option	**50 kW – 200 kW**	**200 kW with demand**
Powerline Carrier	☐	☐
Telephone – Dial-up	●	●
Public Wireless	●	●
Spread Spectrum [15]	☐	☐

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[15] Very vendor specific

Appendix E. Glossary of Terms

Critical Peak Pricing (CPP)	Typically under critical peak schemes, there are set peak and off-peak price levels. In addition, prices for energy in a limited number of critical periods may be several times normal rates. These periods are identified 24 hours in advance and may be for the full peak period or may only include the afternoon and early evening hours.
Demand Response	Actions that result in short-term reductions in peak energy demand.
Demand-Side Management	Actions which result in sustained reductions in energy use for a given energy service, thereby reducing long-term energy and/or capacity needs.
Display	A device, which provides a visual representation of measurement quantities and other relevant information.
Dynamic Pricing	The sale of electricity to a consumer based on prices that change with time. This may be Real Time pricing, prices that change based on defined criteria or critical peak pricing.
Energy Conservation	Any action that results in less energy being used than would otherwise be the case. These actions may involve improved efficiency, reduced waste or lower consumption, and may be implemented through new or modified equipment or behaviour changes.
Energy Efficiency	Using less energy to perform the same function. This may be achieved by substituting higher-efficiency products, services, and/or practices. Energy efficiency can be distinguished from demand-side management in that it is a broad term that is not limited to a particular sponsor such as a utility, a retailer or an energy services company.
Fixed Pricing	The sale of electricity for a price that does not vary with time. The current two-tier price is a fixed price since the criterion is usage-based rather than time-based.
Hourly Ontario Energy Price (HOEP)	The electricity energy price determined by the IMO on an hourly basis by a straight average of the applicable 5-minute Market Clearing Prices.
Interval Metering	An application, which uses a time-stamping method to apportion energy consumption to a specific time period. The energy data is provided in the form of pulses, which represent a specific quantity. As the consumer demand for electricity changes, the meter continuously monitors the energy and generates and /or records pulses proportional to the purchaser consumption. At pre-programmed and predetermined intervals the device emits a time pulse or marks the data stream. This data is now interval data. This interval will never have another pulse added by the meter.

Load Profile Metering	An application which uses a series of consumption data for each interval over a particular time period. The load profile may be considered either as an average load (kW) or total consumption for each interval, and may be used in a time-related electricity demand application.
Load Management	Activities or equipment to induce consumers to use energy at different times of day or to interrupt energy use for certain equipment temporarily in order to meet the objectives of reducing demand at peak times and/or load shifting from peak to off-peak.
Net System Load Shape (NSLS)	The hourly demand curve of a specific distributor once all interval metered loads have been removed. The distributor may have one NSLS or several based on rate classes.
Real Time Pricing	The sale of electricity of gas based on rates which can be changed at any given time.
Real-Time Energy Market (RTEM)	The IMO administered electricity market.
Telemetering System	All devices an equipment use to interpret source electricity or gas meter information at a distance.
Telemetering Device	A device used in a telemetering system to duplicate the register reading of the source meter. Examples of electricity and gas telemetering device types include: • pulse generators and recorders (mechanical and electronic), • totalizers, • duplicators, • prepayment devices, • automatic meter readers and • remote registers.
Time-Of-Use	The sale of electricity or gas based on rates established for certain times and seasons. A TOU function records the usage of electricity at certain times of the day over the length of the billing or meter-reading period. The TOU function has a pre-selected number of rate bins or registers. Each rate bin would have daily energy consumption accumulated with no specific time stamp, except that the consumption was recorded during a predetermined and pre-programmed time period.